	OAH 3-2500-21031-2 MPUC E015/GR-09-1151

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION**

This matter came before Administrative Law Judge Kathleen D. Sheehy for hearing on May 17-19, 2010, at the Offices of the Minnesota Public Utilities Commission, 121 Seventh Place East, Suite 350, St. Paul, Minnesota. The OAH record closed on July 15, 2010.

Christopher D. Anderson, Associate General Counsel, Minnesota Power, 30 Superior Street, Duluth, MN 55802-2093; and Sam Hanson, Thomas Erik Bailey, and Elizabeth M. Brama, Briggs and Morgan, 2200 IDS Center, 80 South 8th Street, Minneapolis, MN 55402, appeared for Minnesota Power (the Company).

Julia Anderson and Linda S. Jensen, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, MN 55101, appeared for the Minnesota Department of Commerce, Office of Energy Security (OES).

Ronald M. Giteck, Assistant Attorney General, 445 Minnesota Street, Suite 900, St. Paul, Minnesota 55101, appeared for the Office of the Attorney General Residential and Small Business Utility Division (OAG/RUD).

Robert S. Lee and Andrew P. Moratzka, Mackall, Crounse & Moore, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, Minnesota 55402, appeared for AreclorMittal USA (Minorca Mine); Blandin Paper Company; Boise, Inc.; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; NewPage Corporation; PolyMet Mining, Inc.; Sappi Cloquet, LLC; USG Interiors, Inc.; United States Steel Corporation (Keewatin Taconite and Minntac Mine); and United Taconite, LLC (collectively the Large Power Intervenors or LPI).

Bride Seifert, Rate Case Intern, Minnesota Chamber of Commerce, 400 Robert Street North, Suite 1500, St. Paul, MN 55101, appeared for the Minnesota Chamber of Commerce (Chamber).

Pam Marshall and Patty Fischer, Energy CENTS Coalition, 823 E. 7th St., St. Paul, MN 55106, appeared for the Energy CENTS Coalition (ECC).

Elizabeth Goodpaster, Staff Attorney, 26 East Exchange Street, Suite 206, St. Paul, MN 55101, appeared for the Minnesota Center for Environmental Advocacy, Isaak Walton League, and Fresh Energy (collectively MCEA).

Robert Harding, Jerry Dasinger, Clark Kaml, Shannon McIntyre, and Rachel Welch participated in the hearing as staff members of the Public Utilities Commission.

STATEMENT OF THE ISSUES

1. Is the test year revenue increase proposed by the Company reasonable, or will it result in unreasonable and excessive earnings?

2. Is the rate design proposed by the Company, including proposed revisions to the customer charges, reasonable?

3. Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

4. What is the appropriate treatment of the investment, costs, and revenues associated with the Company's purchase of the Square Butte transmission line?

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

1. Minnesota Power is an operating division of ALLETE, Inc., a Minnesota corporation with headquarters in Duluth, Minnesota. ALLETE owns other regulated energy businesses, including Superior Water, Light and Power (a subsidiary in Wisconsin), and has an equity ownership interest in Wisconsin-based American Transmission Company (ATC). ALLETE also owns a subsidiary (BNI) that operates a coal mine in North Dakota, as well as a real estate business consisting of land holdings, most of which are in Florida.[1]

2. Minnesota Power provides electricity to approximately 141,000 retail customers in Northern Minnesota. Its 26,000-square-mile service area extends from Bemidji, Park Rapids, and Wadena on the west to the shores of Lake Superior, and from International Falls south to Hinckley.[2]

3. Minnesota Power's retail customer profile is unique among Minnesota's investor-owned utilities, in that its industrial customers use approximately two-thirds of

[1] Ex. 8 at 2 (McMillan Direct).
[2] *Id*.

the retail energy it supplies. It has twelve large power customers (taconite plants, paper mills, and pipelines) that account for 64% percent of the Company's retail revenues.[3]

4. In May 2008, Minnesota Power filed a general rate case seeking to increase rates in the amount of $45 million, or approximately 9.5 percent per year over then-current rates. At that time, the Company had not filed a petition for a rate increase during the preceding 14 years. After a hearing, the Commission granted an increase in the amount of $21 million, or about 4.5%.[4] The Commission's order became effective November 1, 2009.[5]

5. On November 2, 2009, Minnesota Power filed this general rate case seeking to increase rates in the amount of $81 million, or approximately 18.9% per year. In its filing, Minnesota Power proposed a forecasted 2010 calendar year as its test year. The Company also filed a proposed interim rate schedule seeking an interim rate increase of $ 73 million (17.1%).

6. On December 30, 2009, the Commission found Minnesota Power's application to be substantially complete as of November 2, 2009, and it extended the ten-month deadline for completing this case until November 2, 2010.[6] On the same date, the Commission issued orders authorizing Minnesota Power to collect approximately $48 million in interim rates (approximately 60% of the rate request) and initiating a contested case proceeding in the Office of Administrative Hearings.[7]

7. The following parties intervened in this matter: ECC, LPI, the Chamber, Enbridge Energy Limited Partnership (Enbridge), and MCEA.[8]

Public Hearings

8. Public hearings were held on April 13, 2010, at 2 p.m. and 7 p.m. at the Eveleth Range Recreation & Civic Center in Eveleth (11 members of the public attended); on April 14, 2010, at 2:00 p.m. and 7:00 p.m. at the Inn on Lake Superior in Duluth (73 attended); on April 21, 2010, at 7:00 p.m. at the Itasca Community College in Grand Rapids (11 attended); and on April 22, 2010, at 7:00 p.m. at the Morrison County Government Center in Little Falls (15 attended).

9. The ALJ received 89 written comments from members of the public in response to the petition for a rate increase.

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[3] Ex. 8 (McMillan Direct) at 3.
[4] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order (May 4, 2009) (*2008 Rate Case Order*).
[5] *Id*., Order Setting Interim Rate Refund, Amending Order After Reconsideration, and Approving Compliance Filing (Oct. 29, 2009).
[6] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, E-015/GR-09-1151, Order Accepting Filing and Suspending Rates (Dec. 30, 2009).
[7] *Id*., Order Setting Interim Rates and Notice and Order for Hearing (Dec. 30, 2009).
[8] First Prehearing Order (Jan. 21, 2010); Second Prehearing Order (Feb. 17, 2010).

10. Virtually all residential and small business customers who spoke or submitted written comments were opposed to either the size of the increase or to increasing rates at all during a time when economic conditions remain poor and unemployment remains relatively high in Northern Minnesota. Many ratepayers were shocked at the size of the proposed increase following so quickly after the last increase in rates. A number of people specifically objected to receiving an interim rate increase in this case that reduced or eliminated the refund of interim rates they expected from the last rate case.[9]

11. Senior citizens and disabled persons living on fixed incomes generally opposed any increase in rates, except for those who are shareholders of Minnesota Power. Shareholders pointed out that they rely on the company's dividends for retirement income, and they generally advocated in favor of setting a fair rate of return to protect these dividends.

12. A number of persons who spoke at hearings or submitted written comments were opposed to the statutory requirement that utilities invest in renewable energy resources. They generally advocated the use of less expensive resources.

13. Dual-fuel and off-peak customers who recently made substantial investments to switch service based on the cost of fuel oil expressed frustration with electric rate increases.[10]

14. Representatives of Minnesota Citizens Federation Northeast and others objected to proposed changes to the existing Lifeline rate design. The proposed changes would require ratepayers to be qualified on the basis of income in order to receive discounted rates. These speakers believe that residents (especially senior citizens and low-income working people) will find it difficult to apply for assistance even though they may be eligible for it.[11] On the other hand, a few commenters opposed the proposed Lifeline discounts on the basis that such discounts are "forced charity" by ratepayers.[12]

15. A number of persons agreed with newspaper articles referencing the OAG's objections to inclusion of expenses for executive bonuses, travel and entertainment, advertising, lobbying, and use of the Company's aircraft.

16. Two municipalities—the City of Long Prairie and the City of Duluth—pointed out that an 18% rate increase would cause hardship for cities already pressured by reductions in Local Government Assistance (LGA), housing foreclosures, and falling

[9] *See, e.g.*, email from Mary Smith (Jan. 26, 2010); email (Mar. 11, 2010); email from Rick Halvorson (Mar. 11, 2010); Letter from Arthur Englund (Mar. 8, 2010)
[10] Transcript of 2:00 p.m. Public Hearing, Duluth, at 25-26, 32, 43-44.
[11] Transcript of 2:00 p.m. Public Hearing, Duluth, at 29-31, 34-40; Transcripti of 7:00 p.m. Public Hearing, Duluth, at 26-34.
[12] Transcript of 7:00 p.m. Public Hearing, Duluth, at 38-43.

market values. The City of Duluth also specifically objected to proposed changes in the street lighting rate.[13]

17. A representative of the NewPage Duluth paper mill stated that the proposed rate increase would mean an increase in cost of several million dollars per year at a time when the paper industry has been hit hard by the recession. The company has had to shut down two mills in Wisconsin and cut prices. The speaker stated the company is not in a position to absorb these increased costs.[14]

18. Several Duluth businesses—the Edgewater Resort, the Inn on Lake Superior, and Grandma's Restaurants—pointed out that the hospitality industry has suffered substantial declines in business during the current economic recession. They objected to substantial increases in rates coming so closely over a two-year period.[15]

19. The Area Partnership for Economic Expansion (APEX), the Northspan Group, Inc., the Grand Rapids Area Chamber of Commerce, the Economic Development Group in Grand Rapids and Itasca County, and the Initiative Foundation in Little Falls supported recovery of Minnesota Power's economic development expenses.[16]

20. Several speakers commented that Minnesota Power has a lengthy and notable history of supporting the community through corporate contributions and encouragement of employee contributions. The Duluth Chamber of Commerce, the United Way of Greater Duluth, the Second Harvest Northern Lakes Food Bank, the Vice-Chancellor or Finance and Operations at the University of Minnesota-Duluth, and the Duluth/Superior Area Foundation all described the many contributions made by Minnesota Power that benefit the community. They advocated that Minnesota Power be permitted to recover a portion of its charitable contributions based on historic giving patterns, instead of a portion of contributions based solely on amounts contributed in 2009 (as advocated by OES). These organizations believe the Company's level of charitable contributions in 2009 were anomalous and do not fairly represent Minnesota Power's history of giving to the community.[17]

I. USE OF PROJECTED TEST YEAR.

21. As noted above, Minnesota Power proposed the use of a projected 2010 calendar year as its test year.

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[13] *See* Letter from Don Rasmussen, Mayor of City of Long Prairie (Apr. 20, 2010); Letter from David Montgomery, Chief Administrative Officer, City of Duluth (May 5, 2010).
[14] Transcript of 2:00 p.m. Public Hearing, Duluth, at 41-42.
[15] *See* Letter from Justin Steinbach, General Manager, Edgewater Resort (Apr. 21, 2010); Letter from Nikki Anderson, General Manager, Inn on Lake Superior (Apr. 23, 2010); Letter from Brian Daugherty, President, Grandma's Restaurant Company (Apr. 30, 2010).
[16] Transcript of 7:00 p.m. Public Hearing, Duluth, at 21-26; Transcript of 7:00 p.m. Public Hearing, Grand Rapids, at 18-20, 23-24; Transcript of 7:00 p.m. Public Hearing, Little Falls, at 20-24: Letter from Randy Lasky, President, Northspan Group, Inc. (undated).
[17] Transcript of 2:00 p.m. Public Hearing, Duluth, at 60-69; Transcript of 7:00 p.m. Public Hearing, Duluth, at 34-38.

22. The OAG contends that the Commission should deny Minnesota Power's rate petition in its entirety based on use of a forecasted test year and should require, in future cases, that Minnesota Power use only an historical test year.[18]

23. The OAG maintains that the forecasted test year does not provide a reliable basis to set new rates and that the Commission has previously rejected a similar rate increase petition filed by Northern States Power (NSP) that used a forecasted test year. In addition, the OAG contends the filing should be rejected because the Company's rebuttal testimony (which substantially increased the sales forecast) was so different from its original filing as to constitute an entirely new rate case; because Minnesota Power failed to support its proposed budgets for employee travel and entertainment costs; and because of gaps and inconsistencies in Minnesota Power's test year revenue and expense schedules.

24. No other party objected to the use of a forecasted test year.

A. The Commission's 1989 NSP Decision.

25. In 1989, NSP filed a rate increase petition, which the Commission denied completely on the basis that NSP's capital budgeting processes were highly unreliable, with capital budgets overestimated for a four-year period by up to 28%. In addition, NSP had included numerous projects in the test year rate base that did not belong there, including 140 projects that had been canceled or had not been placed in service. As a result, the Commission was unable to conclude that the forecasted rate base was sufficiently reliable for the purpose of setting rates. The same problems were apparent with forecasted operating and maintenance expenses for the test year, which were almost 8% higher than originally budgeted. The Commission characterized the expense budgets as exhibiting "roller coaster characteristics over the past four years," with significantly higher spending in rate case years than in non-rate case years. Moreover, NSP failed to itemize forecasted expenses by the FERC Uniform System of Accounts or to break down maintenance costs by transmission versus generation groups. The Commission's decision was based not on NSP's use of a projected test year, but on NSP's failure to substantiate that the projected test year had a clear and substantial link with actual historical experience.[19]

26. In this case, no party has questioned the historical accuracy of Minnesota Power's capital budgeting process. In fact, there are relatively few disputes about the proposed rate base in this case, none of which involve either over-budgeting or under-spending. The major disputes have to do with cost overruns with regard to environmental upgrades made to Boswell 3, and the issue whether, as a policy matter, the Company's budgeted investments to maintain Boswell 4 should be made at all. The OAG has not argued that Minnesota Power has over-recovered for capital improvements that were not made; rather, it argues that Minnesota Power has spent

[18] Ex. 73 at 9 (Lindell Surrebuttal); OAG Initial Brief at 5-19.
[19] *In the Matter of the Petition of Northern States Power Company (NSP) for Authority to Increase Its Rates*, 1990 WL 488896, Docket No. E-002/GR-89-865 (July 16, 1990).

excessively on capital improvements, which have resulted in excess capacity that ratepayers should not be required to fund.

27. In contrast to the NSP decision, many of the major issues in this case regarding Minnesota Power's expense budgets are the product of the recent economic recession, from which the nation is still recovering. Because of downturns in the automobile and steel industries, taconite producers dramatically reduced, and in some cases entirely shut down, their production of taconite. Minnesota Power's average monthly loads dropped almost 25% in 2009 compared to 2008.[20] In response to the 2009 downturn, Minnesota Power was required to reduce its operating expenses, delay some capital projects, and sell surplus energy at wholesale rather than retail rates.[21] In 2009, the Company earned a return on common equity of 5.29%, compared to its authorized return of 10.74%.[22]

28. Although there are a number of disputes in this case as to whether 2010 expense budgets should be larger than 2009 actual expenses, those disputes reflect real differences of opinion about the degree of recovery that should be anticipated from the recession of 2009, or, in some instances, the propriety of making adjustments to Minnesota Power's initial filing based on updated or corrected information.

29. The issues in this matter are quite different from those the Commission faced in the 1989 NSP case. The Administrative Law Judge concludes that the Commission's decision in the NSP matter should not preclude the use of a projected test year in this case.

B. Revision of the Sales Forecast.

30. In Minnesota Power's last rate case, it used a projected test year of July 1, 2008, to June 30, 2009. Rates for the Large Power class were based on the assumption that usage would continue at 2008 levels for all except one customer.[23] As noted above, the usage assumptions for this class of customers did not hold true in 2009.

31. In its original filing (made in November 2009), Minnesota Power predicted some economic improvement for the 2010 test year. In its rebuttal testimony (filed in April 2010), Minnesota Power increased its sales forecast in response to nominations received from large power customers in March 2010, and it made other adjustments that decreased its claim for a revenue deficiency to $71.8 million.[24]

32. The record reflects that the forecast increases were based largely on changes in anticipated demand by the Company's Large Power customers since the time of the initial filing, as well as the use of updated economic data. The rebuttal filing

[20] Ex. 8 (McMillan Direct) at 8-11.
[21] *Id*. at 14-20.
[22] Ex. 9 (McMillan Rebuttal) at 12.
[23] *Id*. at 14-15.
[24] *Id*. at 21.

did create many changes, but there was good reason for it. The economy improved, and the Large Power customers were more optimistic about production. Moreover, these forecast changes were to the benefit of ratepayers. The OAG's argument that sales forecast revisions render the initial filing inadequate is without merit.

C. Support for Employee Expenses.

33. The OAG argues that Minnesota Power's failure to support its proposed budgets for certain costs and expenses provides a basis for rejecting the use of a proposed test year or for requiring the use of a historical test year in the future.

34. In support of this argument, the OAG's Initial Brief cites to excerpts of Minnesota Power's responses to 14 Information Requests (IRs), most of which are not contained in the evidentiary record. In its Initial Brief, the OAG requested that, if it is deemed necessary, these be accepted as late-filed exhibits for the "limited purpose" of showing that the responses did not provide the data requested.[25] Minnesota Power moved to strike these portions of the brief. The Administrative Law Judge denied both the motion to strike and the informal request by the OAG to receive the IRs as late-filed exhibits.[26] The Administrative Law Judge cannot rely on evidence that is not in the record for even the "limited purpose" described above.[27]

35. Most of the referenced IRs deal with the issue of how Minnesota Power developed its test year employee expense in the amount of $1.84 million. As noted in the findings pertaining to this issue, Minnesota Power forecasted 2010 test year expense based on total actual expense amounts for 2008. Based on the information provided by Minnesota Power in response to information requests, the OAG provided testimony and scores of exhibits in support of its argument that the test year expense level should be further reduced.[28] To the extent the OAG has suggested that it was denied access to critical information about employee expenses, the argument mischaracterizes the record. There may be legitimate issues as to whether it is appropriate for ratepayers to pay such expenses in the amounts claimed; however, the OAG has failed to demonstrate that the entire filing should be rejected because the proposed expenses were unsupported by actual historical cost data.

36. Moreover, even assuming the claimed $1.8 million in employee expenses in this case were completely unsupported, that assumption would not provide a legal or factual basis to reject the entire filing. Minnesota Power's rate petition seeks a return on substantial capital investments (about $300 million) made since the last rate case. The

[25] OAG Initial Brief at 11 n. 17. Minnesota Power's responses to IR Nos. 109, (contractor O&M), 222 (CCOSS), 601, 602, 609, 610, 618, 621 (all pertaining to employee expenses), and 701 (recalculation of certain schedules) are not in the record.
[26] Order on Motion to Strike and to Supplement the Record (Aug. 16, 2009).
[27] There was discussion at the conclusion of the hearing about how to handle other information that might be produced after closure of the evidentiary record (the planned maintenance outage information relevant to the sales forecast issue). *See* Tr. 3:164-65. But there was no discussion of including these IRs as late-filed exhibits at any time.
[28] *See, e.g.*, Ex. 75 & Schedules RLS 1-14 (Smith Rebuttal).

OAG's argument as to the reduction in amount of the proposed employee travel and entertainment test year expense will be further addressed below.

D. Alleged Gaps in Test Year Schedules.

37. Finally, the OAG's claim that the filing should be rejected because of gaps and inconsistencies in Minnesota Power's test year schedules is unpersuasive. The OAG initially contended that there were discrepancies between the Company's test year revenue schedule and Cost of Service schedule.[29] In Rebuttal, the Company explained how the two schedules were organized and could be reconciled.[30] The OAG then argued that Minnesota Power used the total company revenue amount as its test year revenues in the Cost of Service Schedule. The OAG asserted this was inappropriate because total company revenues include revenues associated with non-Minnesota retail operations.[31] It further maintains that because Minnesota Power cannot identify rate base and expenses associated with these non-Minnesota retail revenues, it has failed to fairly present its rate case information.[32]

38. The Administrative Law Judge concludes that the premise of this argument is faulty. Minnesota Power did not use total company revenues as its test year revenues in the Cost of Service Schedule. Minnesota Power provided schedules that link both total company and Minnesota retail revenues with the cost of service.[33] The record provided by the OAG provides no basis for concluding either that Minnesota Power has failed to match expenses with revenues or that it has included rate base or expenses associated with non-Minnesota retail revenues in the test year.

E. Recommendation.

39. In the last rate case, the OAG made essentially the same argument with regard to the use of a projected test year, and the Commission rejected it. There the Commission found the use of a projected test year to be reasonable. The Commission noted that it has allowed the use of a projected test year in other rate cases and that the reliability of a proposed test year does not depend on whether it is historical or projected, because in either case the numbers can be and typically are adjusted to accurately reflect known future changes or expectations for the period at issue.[34]

40. The Commission has allowed regulated utilities the flexibility to select either an historic or forecasted test year, as long as the assumptions supporting the use of a forecasted test year are adequately substantiated. The Administrative Law Judge concludes that the record in this case is adequately developed to set just and reasonable rates, and accordingly recommends that the Commission (1) find the use of a projected 2010 test year to be reasonable; and (2) continue to allow Minnesota Power

[29] Ex. 71 at 4-6 (Lindell Direct).
[30] Ex. 49 at 6 (Podratz Rebuttal).
[31] Ex. 73 at 10 (Lindell Surrebuttal).
[32] *Id*. at 11.
[33] *See* Ex. 71 at JJL-2 (Lindell Direct); Ex. 49 at 6-7 (Podratz Rebuttal); Ex. 40 at 3-8 (Shimmin Direct).
[34] *2008 Rate Case Order* at 8.

to use either an historic or forecasted test year in future cases as a reasonable place to begin analysis of its revenues and expenses.

II. MULTI-PARTY STIPULATION.

41. During the course of the contested case hearing, Minnesota Power, LPI, OES, MCC, and ECC entered into a Stipulation and Settlement Agreement (the Multi-Party Stipulation), resolving a number of significant disputed issues. Pursuant to the May 18, 2010, Multi-Party Stipulation, these five parties agreed to:

- revised retail and wholesale margins for the 2010 test year;
- recalculated jurisdictional allocations to reflect the revised test year retail and wholesale sales;
- a mechanism to allow Minnesota Power's retail rates to be adjusted without bringing a rate case to reflect a significant increase in retail sales to the Large Power class;
- the return on equity, capital structure, and cost of debt for the test year;
- certain O&M expense adjustments for Boswell 3 and 4; and
- the environmental retrofit costs for Boswell 3.

42. In addition, Minnesota Power and LPI entered into a separate Stipulation and Settlement Agreement (LP Rate Design Settlement) that resulted in the Company withdrawing a proposed 50% take-or-pay revision to its Large Power tariff, as well as a proposed non-uniform nomination demand charge.

43. The parties' agreement regarding retail revenues, wholesale margins, the jurisdictional allocation factor, and the margin impact analysis was contingent upon six Large Power customers nominating a total of 662 MW or more by August 2, 2010.[35] This contingency was satisfied.[36]

44. The settling parties—Minnesota Power, LPI, OES, MCC, and ECC—all advocate that the Commission approve the Multi-Party Stipulation and the LP Rate Design Settlement.[37] For a variety of reasons, described below, the OAG maintains these settlements should be rejected.

45. The Administrative Law Judge concludes, after considering the evidentiary record and the terms of the stipulations, that the OAG's objections should not preclude approval of the terms of the Multi-Party Stipulation. These agreements represent a fair and reasonable compromise of significant issues, they are supported by the record, and the Administrative Law Judge recommends that the Commission approve them.

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[35] Ex. 108, Section 1.G.

[36] Letter from Christopher D. Anderson to Administrative Law Judge (efiled Aug. 4, 2010).

[37] These settlement agreements would substantially resolve the financial issues in this case. If these agreements are approved, Minnesota Power calculates the gross revenue deficiency as $60,459,400; OES calculates the deficiency as $53,819,538, assuming its proposed adjustments are implemented. *Compare* Minnesota Power Initial Brief Appendix 3 *with* Ex. 107 at DVL-H-2.

A. Retail Revenues and Margins.

46. In Minnesota Power's initial filing, it presented a test year retail sales forecast using the forecasting methodology employed for its 2009 Annual Forecast Report, or AFR, filed in Minnesota Power's 2009 Integrated Resource Planning (IRP) Docket.[38] In consultation with the OES, Minnesota Power had developed a new forecasting methodology in the AFR that employs structural econometric techniques to project monthly customer counts, load demand, and energy sales for each revenue class based on independent forecasts of a variety of economic and demographic variables.[39] Key changes were (1) the use of monthly versus annual forecasting for each revenue class; (2) the use of a new weather series; (3) the disaggregation of the Industrial revenue class into the industries that make up that class (i.e., mining, forest/paper, and other industrial) for forecasting purposes; and (4) the use of Federal Reserve indices of industrial production as a data source in the Industrial revenue class forecasting process.[40]

47. Minnesota Power's initial 2010 test year retail sales forecast was 7,547,250 MWh, as follows: [41]

Residential	1,081,858
Commercial	1,175,074
Industrial	5,217,049
Govt & Lighting	73,269
Total	7,547,250

48. OES,[42] OAG,[43] and LPI[44] filed direct testimony challenging Minnesota Power's retail sales forecast. These parties all expressed concerns over one aspect or another of Minnesota Power's forecasting process. These parties used different methods that resulted in a higher forecast of energy sales to the Residential, Commercial (General Service and Large Light & Power), and Industrial classes. The recommended increases to Minnesota Power's forecasts were as follows:

Proposed Increase (MWh)	
OES Residential	20,142
OAG Residential	14,850
OES Commercial	38,507
OAG Commercial	19,250

[38] *See* Docket E-015/RP-09-1088; Ex. 19 at 3-7 (J. Pierce Direct).
[39] Ex. 19 at 3 (J. Pierce Direct); Ex. 21 at 2 (J. Pierce Rebuttal).
[40] Ex. 19 at 5 (J. Pierce Direct).
[41] *Id*., Schedule 7.
[42] Ex. 99 at 3-19 (Ham Direct).
[43] Ex. 74 at 7-14 (Smith Direct).
[44] Ex. 66 at 25-29 (Baron Direct).

OES Industrial	1,683,786
OAG Industrial	983,104

49. The OES sales forecast would translate to an increase of approximately $3 million in the margin for the Residential/Commercial classes and an increase of $35.4 million in the margin for the Industrial class.[45] The OAG's sales forecasts would translate to a margin increase considerably lower than that of the OES. LPI did not express its proposed increase in terms of MWh, but advocated an increase in margin from the Large Power Class of $29 million.

50. Minnesota Power contended that various adjustments to test year energy sales proposed by the OES, OAG, and LPI were flawed. For instance, the OES forecast for the Industrial rate class was higher than during even the best of economic times and assumed constant output year round, with no allowance for planned maintenance, seasonal reductions in production levels, or lower customer load factors.[46] The OAG's proposed adjustments for the Residential and Commercial classes resulted in significantly lower sales than Minnesota Power's updated forecast for the same classes, because the OAG used different key economic variables.

51. In its Rebuttal testimony, Minnesota Power provided an updated forecast using the same econometric forecasting structure, using more recent data for key economic variables.[47] Minnesota Power proposed to increase energy sales to retail classes by approximately 1.3 million MWh above its original forecast as follows:

Rebuttal Increase (MWh)

Residential	19,183
Commercial	29,998
Industrial	1,219,255

52. Minnesota Power's rebuttal forecast would translate to an increase of approximately $1.865 million in the margin for the Residential/Commercial classes and an increase of approximately $24.4 million in the margin for the Industrial class.[48]

53. In its surrebuttal, OES agreed with Minnesota Power's revised Industrial class sales projection, on the basis that it properly reflected taconite production outages, whereas the OES sales projection had not; however, OES continued to recommend its previously proposed adjustments to the Residential, General Service, and Large Light & Power rate classes.[49]

[45] Ex. 50 at Schedule 3 (Podratz Rebuttal).
[46] Ex. 25 at 12-13 (Seeling Rebuttal); Ex. 20 at 14-16 (Pierce Rebuttal); Ex. 9 at 16-17 (McMillan Rebuttal).
[47] Ex. 50 at Schedule 3 (Podratz Rebuttal).
[48] *Id*.
[49] Ex. 101 at 1-3 (Ham Surrebuttal).

54. The LPI did not explicitly accept Minnesota Power's upward adjustment of sales to the Industrial revenue class, but it did not file surrebuttal testimony objecting to the adjustment.

55. The OAG objected to Minnesota Power's rebuttal adjustment of retail sales, even though the Company's proposed sales forecast for each class exceeded that proposed by OAG itself. The OAG argued that although Minnesota Power's updated sales forecast for the Residential and Commercial revenue classes was "in the ball park," the Company did not provide enough information for OAG to determine whether an even larger sales increase was warranted.[50] With regard to the Industrial class, the OAG recommended that the sales estimate provided by the OES be adopted by the Commission.[51]

56. The Multi-Party stipulation provides, in relevant part:

> The Settling Parties agree that Minnesota Power will realize test year margins from the Large Power class of $139.6 million (or a $24.4 million increase net of fuel and purchased energy costs over the amount originally identified by Minnesota Power in its initial testimony).
>
> The Settling Parties further agree that Minnesota Power will realize test year margins from the Residential/General Service/LLP classes at a combined $159.3 million level (or a $3.0 million increase net of fuel and purchased energy costs over the amount originally identified by Minnesota Power in its initial testimony).

57. The Multi-Party Stipulation accordingly incorporates (1) Minnesota Power's revised test year retail sales revenues and margins for the Large Power rate class; and (2) the OES's revenues and margins for the Residential, General, and Large Light & Power rate classes.[52]

58. The OAG is the only party that challenges this aspect of the Multi-Party settlement. The OAG argues that the settlement of this issue should be rejected because it understates potential revenues from the Large Power class. The OAG maintains the sales forecast for the Large Power class should be increased by approximately 464,000 MWh, which is the difference between the OES forecast and the number of maintenance hours assumed in the test year for taconite producers.

59. The OAG's objection to the stipulated forecast is based only on the planned maintenance hours for taconite producers; the OAG's proposed figure does not account for seasonal variations in production or changes in customer load factors, which the OES acknowledged could affect the accuracy of its forecast. In addition, the Adjustment Mechanism for Large Power Load (see below at Findings 69 to 76) provides

[50] Ex. 76 at 5-6 (Smith Surrebuttal).
[51] Ex. 76 at 9 (Smith Surrebuttal).
[52] *Compare* Ex. 49 at Schedule 3 (Podratz Rebuttal) *with* Ex. 108, Sections 1.A and 1.B (Multi- Party Stipulation).

something of a hedge for customers in the event of a substantial increase in Large Power sales, in that rates could be adjusted to the benefit of ratepayers without the need for filing a rate case. Under all these circumstances, the Administrative Law Judge concludes the agreement on Retail Revenues and Margins is a fair and reasonable resolution of the parties' differences.

B. Wholesale Margins.

60. There is an inverse relationship between test year retail sales and wholesale margins; an increase or decrease in retail energy sales to ratepayers directly affects the amount of system energy that is available to sell at wholesale. Greater than expected retail sales during the test year will result in lower wholesale margins, and lower retail sales will result in greater wholesale margins.[53]

61. Based on its initial retail sales forecast, Minnesota Power's initial forecast of test year wholesale margins was $41.5 million.[54] Because of its upward adjustment of test year retail sales in its rebuttal testimony, Minnesota Power made a corresponding adjustment in its rebuttal testimony that decreased test year wholesale margins to $35.2 million.[55]

62. The OES and LPI also proposed to reduce Minnesota Power's test year wholesale margins based on their proposed increases to the retail sales forecast.[56] OES further adjusted the wholesale margins to reflect its assumptions about new and expiring wholesale energy contracts, increased capacity at Boswell 4, and Large Power class production levels.[57] These adjustments led to a test year wholesale margins level of $39.3 million.[58] Based on further adjustments in its surrebuttal testimony, OES proposed wholesale margins for the test year of $40.2 million.[59] The LPI proposed $27.9 million in test year wholesale margins to reflect its proposed increase in test year retail sales.[60]

63. The OAG argued that wholesale margins do not adequately compensate ratepayers for the costs of generating the energy. It proposed that Minnesota Power's wholesale margins for the test year should be reduced to $35 million, but it also recommended that another $35.5 million in wholesale revenues should be recognized in the test year as a proxy for what it characterized as sales of "excess system capacity."[61]

64. The OAG calculated what it believed to be Minnesota Power's excess capacity as 286 MW over the next four years, and it developed a value of $124,000 per MW based on Minnesota Power's contract to sell power to Basin Electric. In total, the

[53] Ex. 23 at 7-10 (Seeling Direct).
[54] *Id*. at 6.
[55] Ex. 25 at 3 (Seeling Rebuttal).
[56] Ex. 99 at 16-17 (Ham Direct); Ex. 94 at 43 (N. Campbell Direct); Ex. 66 at 28-29 (Baron Direct).
[57] Ex. 99 at 17-19 (Ham Direct); Ex. 94 at 46-52 (N. Campbell Direct).
[58] Ex. 94 at 60 (N. Campbell Direct).
[59] Ex. 96 at 49 (N. Campbell Surrebuttal).
[60] Ex. 66 at 29 (Baron Direct).
[61] Ex. 71 at 20-22 (Lindell Direct).

OAG recommended a $35.5 million credit to the revenue requirement, along with a reduction in wholesale asset-based margins to $35 million.[62] The OAG also recommended that Minnesota Power be required to "defer excess margin revenue above the amount established as a credit in base rates if it exceeds five percent or $1.5 million."[63]

65. While Minnesota Power and OES agreed that test year wholesale margins must be reduced to reflect the agreed-to increase in Minnesota Power's test year retail sales, they differed on how Boswell 4 capacity, Boswell 3 and 4 outages, MISO market energy price forecasts, and fuel costs would affect the amount of the wholesale margins associated with the agreed-to level of retail sales.[64]

66. The Multi-Party Stipulation provides for $37.7 million in test year wholesale margins, which is the mid-point between Minnesota Power's proposed $35.2 million and OES's $40.2 million.[65]

67. Although the OAG does not object specifically to this settlement provision, it continues to argue that wholesale margins are an inappropriate way to account for excess capacity and that "MP's retail customers will pay the costs of excess capacity in exchange for some conservative level of wholesale margins to be credited to the retail revenue requirement."[66] The OAG argues that ratepayers would be better served if all excess capacity costs were removed from retail rates and that Minnesota Power should be allowed to operate that business as a non-regulated activity.[67]

68. The OAG has offered no evidence or analysis to show that the level of wholesale margins agreed to by the settling parties does not adequately compensate ratepayers for the cost of generating the energy. The resolution of the dispute over test year wholesale margins reached by the settling parties is fair and reasonable based on the record.

C. Adjustment Mechanism for Large Power Load.

69. In response to Minnesota Power's identification of the decline in Large Power class sales in 2009 as one of the principal reasons for filing this rate case, OES proposed the creation of a rate adjustment mechanism under which the Company would be required to make a filing in the event there is a significant increase in Large Power revenues, so that the Company's rates could be adjusted to reflect that increase and the associated reduction in wholesale revenues, as well as any increase in incremental costs not offset by customer revenue contributions.[68] The OES recommended that a significant decline in Large Power production be handled by Minnesota Power through

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[62] Ex. 71 at 18-25 (Lindell Direct).
[63] *Id*. at 23; *see also* Ex. 72 at 6-9 (Lindell Rebuttal); Ex. 73 at 25 (Lindell Surrebuttal).
[64] *Compare* Ex. 25 at 8-9, 12-13 (Seeling Rebuttal) *with* Ex. 101 at 3-7 (Ham Surrebuttal).
[65] Ex. 108 at Section 1.C (Multi-Party Stipulation).
[66] OAG Initial Brief at 29-30.
[67] *Id*.
[68] Ex. 94 at 54-57, 60-61 (N. Campbell Direct).

the filing of a rate case, or possibly through the adjustment mechanism if a Large Power customer left the system for a period of more than one year.[69]

70. In rebuttal, Minnesota Power indicated its willingness to explore the OES proposal.[70] LPI did not object to the OES proposal.

71. In testimony, the OAG opposed OES's suggestion to create an adjustment mechanism, on the ground that it would open the door to future, potentially significant rate proceedings that should not be addressed as a miscellaneous rate filing.[71]

72. The Multi-Party Settlement provides that Minnesota Power shall file a Margin Impact Analysis with any new or amended Large Power Electric Service Agreement (ESA) filing, where the new or changed electric demand is 25 MW or greater; provided, however, that no Margin Impact Analysis would be required in the event collective nominations of Large Power customers averaged less than 596 MW for the three nomination periods preceding the date of the ESA filing.

73. The Margin Impact Analysis is defined to include a calculation of net impact on margins; updated actual margins compared to the amounts agreed upon in this settlement; and a description of how the new or amended ESA would impact the Company's last reported and next projected return on equity levels as reported in the its most recent Annual Jurisdictional Report. In addition, the analysis would include information as to the decrease in wholesale margins necessary to provide service to the customer.

74. The agreement requires the use of all rate design and cost of capital decisions made in this rate case. Upon review of the Margin Impact Analysis, any of the settling parties could request the filing of a new general rate case proceeding or petition the Commission for an adjustment to the Company's retail rate levels. Moreover, Minnesota Power agreed not to file a new rate proceeding based solely on loss of Large Power load until the overall load loss exceeds 10%, or LP nominations fall below 596 MW for more than one year; however, Minnesota Power could file a new rate proceeding immediately based on the shutdown or closure of a single Large Power customer.[72]

75. The OAG opposes "the settlement provision regarding single issue ratemaking."[73] It urges the Commission not to depart from its policy of disallowing single-issue ratemaking. In addition, the OAG contends the agreement would allow the settling parties to petition for a rate adjustment, but presumably would not allow non-settling parties the same right, in violation of Minn. Stat. § 216B.07, which precludes

[69] Ex. 94 at 55 (N. Campbell Direct).
[70] Ex. 25 at 14-15 (Seeling Rebuttal).
[71] Ex. 72 at 11-12 (Lindell Rebuttal).
[72] Ex. 108 (Multi-Party Settlement).
[73] OAG Initial Brief at 21.

utilities from making or granting any unreasonable preference or advantage to any person or subject.[74]

76. The record in this case is clear that a significant upward or downward shift in Large Power class revenues does have a material impact on Minnesota Power's revenue requirements. In light of this, the parties to the Multi-Party Stipulation crafted a mechanism that identifies Large Power production increases that may trigger an adjustment in rates to the benefit of ratepayers, without the need to file a rate case, and a reduction in Large Power production that can, on its own, justify the filing of a general rate case for the benefit of shareholders.[75] The agreement would not limit the Commission's ability to require the filing of a rate case, nor would it preclude the OAG from filing a petition for a rate adjustment or call for the filing of a general rate case. The agreement would not bind the non-settling parties in any way. The Administrative Law Judge concludes that the proposed mechanism is fair and reasonable and is supported by substantial evidence in the record.

D. Jurisdictional Allocations.

77. No party raised any objection to Minnesota Power's initial jurisdictional allocation of costs.[76] As noted above, Minnesota Power projected increased test year retail sales revenues in its rebuttal testimony, which meant that more of the total service costs of the Company were attributable to serving the Minnesota retail jurisdiction. The jurisdictional allocation of costs was recalculated to reflect this shift and resulted in $11.5 million in additional cost assigned to the Minnesota jurisdiction.[77]

78. The OES accepted the Company's revised jurisdictional factors and cost allocations.[78] The LPI, MCC, and ECC joined OES in entering into the Multi-Party Stipulation, which specifically adopts them.[79]

79. The OAG did not accept the revised jurisdictional factors, claiming that the parties did not have adequate time to conduct discovery and analyze them.[80]

80. The OAG objects to the settlement of this issue. It argues that because Minnesota Power has a higher rate of return on FERC wholesale operations than on its Minnesota retail operations, costs must be improperly allocated to the Minnesota retail jurisdiction.[81]

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[74] OAG Initial Brief at 22.
[75] Ex. 108, Sections E, F, and G (Multi-PartyStipulation).
[76] Ex. 40 at 3-8 (Shimmin Direct).
[77] Ex. 42 at 11-14 (Shimmin Rebuttal).
[78] Ex. 96 at 35 (N. Campbell Surrebuttal); Ex. 101 at 3 (Ham Surrebuttal).
[79] Ex. 108, Section 1.D.
[80] Ex. 73 at 24 (Lindell Surrebuttal).
[81] *See* Exs. 43 & 44; OAG Initial Brief at 27-29. In its brief, the OAG contends that Minnesota Power "offered no explanation" for the disparity in rates of return when asked about it during the hearing. The record reflects that the OAG did not ask for an explanation, it merely asked the witness to confirm the OAG's calculations as to the different rates of return. Tr. 2:92-93.

81. No other party argues that it was unable to examine the revised jurisdictional allocations for the purpose of determining their accuracy. The OAG's argument that a higher FERC rate of return "must" mean that costs were over-allocated to the Minnesota retail jurisdiction is speculative and provides no basis for rejecting the settlement provision. The record supports a finding that the stipulated resolution of this issue is fair and reasonable.

E. Boswell 3 Rate Base.

82. Minnesota Power's initial rate case filing sought rate base recovery of approximately $240.5 million invested in its 2007-2009 retrofit at Boswell Energy Center, Unit 3 (Boswell 3).[82] This investment amount was reduced to $237.8 million in rebuttal to reflect adjustments made between the time of the Company's November 2, 2009 rate case filing, and the completion of the project in December 2009.[83] The primary reason for the difference between the estimated and final cost was an accounting shift of improvements that benefited the entire Boswell Energy Center away from the Boswell 3 project and into "common facilities."[84] LPI and OES do not object to this shift.[85]

83. The purpose of the Boswell 3 retrofit project was to reduce emissions of mercury, nitrous oxide, sulfur dioxide, and particulate matter in compliance with environmental regulations.[86] The emission reductions have exceeded 90% for SO2, NOx, mercury, and particulate matter.[87] These improvements could save the Company between $7 million and $16 million over the life of the retrofit in reduced need to purchase SO2 and NOx emission allowances.[88]

84. The largest disputed issue regarding Boswell 3 was that the total cost of the Boswell 3 project increased significantly from the initial 2006 rider filing. OES and LPI objected that the final cost of the project – $237.8 million – exceeded the Company's 2006 estimate of $198.2 million. Those parties recommended reductions in the Company's rate base recovery.[89]

85. OES initially proposed that the difference between the $240.5 estimated final cost and the Company's $198.2 million initial estimate set forth in the Boswell 3 Rider docket should be shared equally between ratepayers and shareholders.[90] OES therefore proposed to reduce Boswell 3 rate base by $21 million (($240.5 M - $198.2 M)

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[82] Ex. 11 at 23 (Rudeck Direct).
[83] Ex. 12 at 3 (Rudeck Rebuttal)
[84] Tr. 1:143-44 (Minke).
[85] Ex. 12 at 3 (Rudeck Rebuttal); Ex. 56 at 19 (Kollen Direct); Tr. 3:134-35 (N. Campbell).
[86] Ex. 11 at 17 (Rudeck Direct).
[87] Ex. 12 at 37 (Rudeck Rebuttal).
[88] *Id*. at 20-21.
[89] Ex. 94 at 19 (N. Campbell Direct); Ex. 56 at 25 (Kollen Direct).
[90] Ex. 94 at 19 (N. Campbell Direct).

÷ 2 = $21 million).[91] OES did not factor into its consideration any long-term savings achieved by the retrofit.

86. LPI objected on the basis that the Company did not provide sufficient information or support to justify the cost increase and asserted that there were inconsistencies in the data the Company provided to explain the cost overrun.[92] LPI further essentially asserted that the Company should be providing sufficient data that one could compare item-by-item expenditures against the same line items from an original project budget.[93] LPI concluded that because the Company could not make this direct comparison, the rate base recovery for Boswell 3 should be reduced to $206.773 million, based on its conclusion that the Company had justified costs of $8.573 million beyond its original estimate for Boswell 3.[94] The LPI also initially suggested that the Company knew in 2006 that its costs would be higher than $198.2 million, but it later acknowledged in testimony that "the original cost estimate was prepared by experienced engineers and evaluated by the Company's own engineers" and that "the Company's engineers, outside and inside, still considered the estimate accurate" as of August 2007.[95]

87. Through the Information Request process, informally, and in rebuttal, the Company provided significant explanation and data regarding the Boswell 3 construction process.[96] Minnesota Power further explained that a line-by-line comparison between the original estimate and final cost was not possible or practicable, because on its face the original estimate was conceptual in nature and did not lend itself to line-by-line comparison.[97] Minnesota Power maintained that the appropriate consideration was whether the Company undertook a prudent process in managing the Boswell 3 retrofit construction, and whether the final project cost is reasonable and prudent in light of the benefits conferred by the project.[98] The Company established that the retrofit resulted in higher emission reductions at a lower per-pound cost than initially projected, and that given the highly competitive generation unit construction environment during which the Boswell 3 retrofit project had to be conducted to satisfy legislative and regulatory environmental mandates, the Company had limited means to further control or reduce costs.[99]

88. In surrebuttal, OES reduced its downward adjustment to Boswell 3 rate base to $19.8 million, or half of the difference between the original estimate ($198.2 million) and the Boswell 3 final cost ($237.8 million).[100] OES continued to aver that shareholders and ratepayers should share in the cost overrun, but reduced its

[91] Ex. 94 at 19 & NAC-7 (N. Campbell Direct).
[92] Ex. 56 at 5-20 (Kollen Direct).
[93] *E.g.*, Ex. 57 at 8 (Kollen Surrebuttal).
[94] Ex. 56 at 20 (Kollen Direct).
[95] Ex. 58 at 5 and 6 (Kollen Surrebuttal).
[96] Ex. 12 at 2-44 (Rudeck Rebuttal); Ex. 16 at 3-17 and Schedules 1 through 22 (Minke Rebuttal).
[97] Ex. 12 at 21 (Rudeck Rebuttal).
[98] *Id*.
[99] Ex. 12 at 8-10 (Rudeck Rebuttal).
[100] Ex. 96 at 12 (N. Campbell Surrebuttal).

adjustment to reflect that the final cost of the retrofit was lower than the final estimate.[101] OES further stated that it did not take the position that there was a lack of information regarding the cost increase.[102] LPI continued to assert that the increase was not adequately supported, but accepted some of the Company's explanation so that LPI's proposed recovery on Boswell 3 retrofit investment was increased by approximately $3 million to $209.473 million. Thus, at the outset of the evidentiary hearing, Minnesota Power contended that $237.8 million should be recovered in rate base for the Boswell 3 project; OES contended that $218 million should be recovered; and LPI contended that approximately $209.5 million should be recovered.

89. The debate between the parties about the appropriate Boswell 3 recovery was resolved by the Multi-Party Stipulation, which provides that the Company may recover and incorporate $223 million into rate base for the Boswell 3 retrofit project.[103] This amount is comprised of the $237.8 million final project cost less OES's $19.8 million adjustment, plus $5 million to reflect that the Company provided additional information that reduced the uncertainty in the project cost amount; that ratepayers would receive additional cost savings through reductions in emissions allowances; and that no party contested the ultimate value of the investment. Recovery of $223 million in rate base is a fair and reasonable settlement of the issue.

90. Based on this agreement, the parties further agreed that Minnesota Power will not depreciate more than the $223 million Boswell 3-specific project balance in rate base for regulatory purposes. The OES had included a schedule showing an $846,000 reduction in depreciation expense that corresponded to her initial proposal to reduce Boswell 3 rate base by $21.15 million.[104] OES updated its numbers in surrebuttal to correspond to its reduced proposed adjustment to Boswell 3 rate base, resulting in a proposed $792,000 depreciation expense reduction.[105] LPI concurred with the concept, although its calculations were provided in a different form.[106]

91. However, Minnesota Power argued that its investment in the Boswell 3 environmental retrofit extended the useful life of the plant, thereby already reducing depreciation expense.[107] The Company further argued that reducing the Company's recovery of its investment in the project that reduced the depreciation expense, then decreasing the remaining depreciation expense further, would effectively penalize the Company for reducing depreciation in the first place.

92. The Multi-Party Stipulation strikes a balance between the positions, allowing the Company to recover depreciation expense related to the $223 million Boswell 3 rate base amount included in the stipulation, but no more. This reduces the

[101] Ex. 96 at 12 (N. Campbell Surrebutal).
[102] *Id*. at 14.
[103] Ex. 108 at 3 (Multi-Party Stipulation).
[104] Ex. 94 at Schedule 7 (N. Campbell Direct).
[105] Ex. 96 at 12, and Schedule NAC-S-7 (N. Campbell Surrebuttal).
[106] Ex. 57 at Schedule LK-5 (Kollen Surrebuttal).
[107] Ex. 35 at 4 (DeVinck Rebuttal).

depreciation expense borne by ratepayers and is therefore a reasonable result for this test year.

F. Boswell 3 Tracker Balance.

93. The issue as to the Boswell 3 tracker balance was first introduced in direct testimony filed by OES. OES made reference to Minnesota Power's November 9, 2009, Letter to the Commission, which stated that the Company did not intend to seek recovery of the Boswell 3 tracker balance, which then totaled $20.8 million, until 15 months after the project was completed, as provided in the Commission's Order in Docket No. E015/M-08-1108.[108] OES recommended that the issue be addressed in this rate case and that the Commission disallow recovery of the tracker balance, arguing that requiring customers to pay for both a return on Boswell 3 rate base through interim rates and a return on Construction Work in Progress (CWIP) would unreasonably increase customer costs.[109] OES's argument was premised on the assumption that recovery of the rider balance would occur during a single year.[110]

94. Minnesota Power responded that the Boswell 3 cost recovery rider entitles the Company to a return on CWIP during the period of construction, until the capital project is placed in service.[111] The Company further noted that the alternative method of collecting a return – receiving a return on the funds used during construction (AFUDC) – would actually result in higher costs to customers while diminishing the Company's ability to raise capital.[112] Minnesota Power agreed that the impact on customers is a valid concern that could be addressed in the Boswell 3 docket compliance filing, and that the Company did not necessarily assume any specific time frame for recovery.[113] Finally, the Company clarified that recovery of the tracker balance compensates Minnesota Power for the use of money during the period before the project is placed in service, while the revenue requirement related to including the project in rate base is compensation for the use of the money after the project is placed in service.[114]

95. In surrebuttal, OES agreed that recovering the Boswell 3 tracker balance along with the separate rate base recovery would not be double counting, but noted that the tracker balance would need to be updated to reflect amounts collected from customers since December 21, 2009 (when the Company initially provided information regarding the tracker balance).[115] OES further continued to question whether recovery of the balance was reasonable.[116]

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[108] Ex. 94 at 20 (N. Campbell Direct).
[109] *Id*. at 21-22.
[110] *Id*. at 22.
[111] Ex. 16 at 17 (Minke Rebuttal).
[112] *Id*. at 18-19.
[113] *Id*. at 19-20.
[114] *Id*. at 20.
[115] Ex. 96 at 22 (N. Campbell Surrebuttal).
[116] *Id*. at 24.

96. The Multi-Party Stipulation provides:

> The Settling Parties further agree that unrecovered Boswell 3 Rider revenues were intended to replace AFUDC during the construction phase of this project, and that therefore Minnesota Power shall be able to capitalize on a total Company basis the $20.5 million in unrecovered Rider revenues as Property Plant and Equipment as part of the Boswell 3 project and depreciate them accordingly. Minnesota Power agrees that no further filings, tracker account recovery mechanisms or proceedings of any nature with respect to Boswell 3 ratemaking will be made.[117]

97. As part of a broader resolution, the parties to the Multi-Party Stipulation agreed to capitalize the tracker balance in order to spread recovery from ratepayers over a longer period, thereby minimizing ratepayer impact. This reasonably addresses concerns regarding the potential ratepayer impact of recovery in a single year. The parties further agreed that there is no double-recovery inherent in this process, which is consistent with accounting for return on pre-completion CWIP versus return on rate base. Finally, the parties confirmed that the amount to be capitalized – $20.5 million – is calculated by taking the $20.8 million balance as of December 21, 2009 and subtracting $0.3 million in additional collections as noted in Hearing Exhibit 97.[118] This satisfies the calculation update suggested by OES. This resolution is fair and reasonable.

98. The Multi-Party Stipulation also provides that the Company will capitalize the unrecovered Boswell 3 Rider revenues as Property Plant and Equipment on a total Company basis "and depreciate them accordingly."[119] No party contested the Company's depreciation of the capitalized rider balance in written testimony or at the evidentiary hearing. It is appropriate for a Company to depreciate a capitalized investment, and the Multi-Party Stipulation merely reflects that common understanding. This is a fair and reasonable result.

G. Boswell 3 and 4 O&M Expense.

99. ***Boswell 3 O&M.*** Minnesota Power's initial rate case filing included incremental test year O&M expenses related to the new environmental control equipment at Boswell 3.[120] The Company acknowledged that certain of these costs totaling $1.023 million, or $0.844 million on a Minnesota jurisdictional basis, were non-recurring.[121] LPI argued that these non-recurring costs should be removed from the Company's rate case revenue requirement and capitalized to CWIP in accordance with the FERC Uniform System of Accounts.[122] In response, Minnesota Power proposed to capitalize a portion of this amount related to laboratory equipment to comply with FERC

[117] Ex. 108 at 3 (Multi-Party Stipulation).
[118] Tr. 3:136-37 (N. Campbell); Ex. 96 at 47 (N. Campbell Surrebuttal).
[119] Ex. 108 at 3 (Multi-Party Stipulation).
[120] Ex. 11 at 29-30 (Rudeck Direct).
[121] Ex. 55 at Schedule LK-8 (Kollen Direct).
[122] Ex. 56 at 25 (Kollen Direct).

rules.[123] The Company proposed to defer all other non-recurring costs so that they could be amortized over three years, which it considers a reasonable period and reflective of the expected timing of its next rate case.[124] LPI continued to recommend capitalizing the expenses, or deferring and amortizing them over the service life of the new equipment.[125]

100. The Multi-Party Stipulation would cause the Minnesota jurisdictional amount of expenses ($0.8 million) to be capitalized to CWIP in accordance with the FERC Uniform System of Accounts.[126] This reduces the Company's revenue requirement, is not inconsistent with either party's position, and is a fair and reasonable resolution of this issue.

101. ***Boswell 4 O&M.*** The Company's initial rate case filing included $3.25 million in incremental O&M expense related to the Boswell 4 extended outage scheduled for October 2010.[127] LPI objected to the Company's accounting for these expenses, arguing that because they are non-recurring expenses, they should not be fully recovered during a single test year; rather, they should be normalized to avoid over-recovery.[128] LPI proposed amortizing the expenses over three years, thereby reducing O&M expenses on a total company basis by $2.167 million, or on a Minnesota jurisdictional basis by $1.787 million. Minnesota Power disagreed, noting that "without exception three to five multi-week unit maintenance outages occur each year across Minnesota Power's system... ."[129] Furthermore, Boswell 3 and 4 alone typically have "major scheduled maintenance outages ranging from two to eight weeks every other year."[130] The Company gave examples of outages in recent years, and asserted that Minnesota Power has already reduced the cost of the Boswell 4 2010 outage.[131]

102. LPI further argued that the O&M expenses will extend the life of the facility such that the costs should be deferred and amortized.[132] Minnesota Power responded that this is an erroneous assumption, as O&M expenses merely maintain the existing useful life of a plant rather than extend it.[133]

103. The Multi-Party Stipulation provides that the non-recurring Boswell 4 O&M expenses of $3.25 million will be amortized over three years as proposed by LPI. While there are reasonable arguments on both sides of this issue, for purposes of resolution, amortizing the expenses over three years is fair and reasonable, and has the effect of reducing the Company's test year revenue deficiency by $2.167 million on a total Company basis or $1.8 million on a Minnesota jurisdictional basis.

[123] Ex. 49 at 20 (Podratz Rebuttal).
[124] *Id*. at 21.
[125] Ex. 57 at 21 (Kollen Surrebuttal).
[126] Ex. 108 at 3 (Multi-Party Stipulation).
[127] Ex. 56 at Schedule LK-9 (Kollen Direct).
[128] Ex. 56 at 26 (Kollen Direct).
[129] Ex. 12 at 46 (Rudeck Rebuttal).
[130] *Id*. at 47.
[131] *Id*. at 47-48.
[132] Ex. 57 at 21 (Kollen Surrebuttal).
[133] Tr. 1:53 (Rudeck).

H. ROE, Cost of Debt, and Capital Structure.

104. Minnesota Power initially recommended an overall rate of return (ROR) of 8.74%, based on a return on equity (ROE) of 11.25%, a cost of debt of 5.75% and a capital structure with an equity ratio of 54.29% and long-term debt of 45.71%.[134] Several parties objected to these proposals.

105. ***ROE*.** Minnesota Power initially contended that the appropriate ROE was 11.5%.[135] It based that conclusion primarily on the results of a discounted cash flow (DCF) analysis of a proxy group of 10 comparable utilities, which produced results, using 30 day average stock prices, between 9.88% and 11.98%.[136] It then reviewed the degree to which the risk of an investment in Minnesota Power was greater than that of the proxy companies, based on the magnitude of Minnesota Power's capital investment program, its customer concentration and its reliance on coal generation.[137] It adjusted these results for flotation costs.[138] Using the 30-day average market prices, its analysis produced a range of 10.05% to 12.14%, with a mean of 11.06%.[139] It concluded that the ROE for Minnesota Power was 11.5%.[140] In rebuttal testimony, the analysis was updated to note that the DCF results had declined somewhat, and the recommended ROE was revised to 11.25%.[141]

106. The OES recommended an ROE of 10.68%, based on the results of a DCF analysis applied to two proxy groups – an electric comparison group and a combination comparison group.[142] In surrebuttal, the OES updated its analysis to revise the ROE recommendation to 10.38%.[143]

107. The LPI also provided testimony on ROE, recommending an ROE of 9.70% based primarily on a DCF analysis applied to a comparison group of sixteen electric companies.[144] In surrebuttal, the LPI provided an updated analysis, but continued to recommend an ROE of 9.7%.[145]

108. The major difference between Minnesota Power and OES concerned the selection of the two proxy groups, the use of a combination company proxy group, and the conclusion that an investment in Minnesota Power was not riskier than investment in the comparison groups.[146] Minnesota Power criticized the inclusion of Edison International in the OES electric group because of the impact of an unusual tax

[134] Ex. 32 at 37-38 (Stellmaker Rebuttal).
[135] Ex. 28 at 2 (Hevert Direct).
[136] *Id*. at 25-26.
[137] *Id*. at 31-42.
[138] *Id*. at 42-48.
[139] *Id*. at 48.
[140] *Id*. at 54.
[141] Ex. 29 at 1 (Hevert Rebuttal).
[142] Ex. 77 at 1, 22 and 28 (Amit Direct).
[143] Ex. 80 at 2 (Amit Surrebuttal).
[144] Ex. 58 at 3 (Baudino Direct).
[145] Ex. 60 at 12 (Baudino Surrebuttal).
[146] Ex. 29 at 46 (Hevert Rebuttal).

settlement; the exclusion of Westar solely because of an SIC code classification; and the exclusion of Progress Energy because of beta criteria.[147] In addition, the OES gave 40 percent weight to its combination group results, even though the combination companies included less risky gas operations, whereas Minnesota Power has no gas operation component.[148]

109. The major differences between Minnesota Power and LPI were more numerous. Minnesota Power disagreed with LPI's selection of proxy groups, its use of unusual growth rate data, and its failure to adequately adjust for flotation costs.[149] LPI's comparison group also included Edison International, whose earnings were significantly affected by a tax settlement, and other companies that had only 50% of revenues from utility operations.[150] In addition, Minnesota Power maintained that the LPI did not screen companies for risk comparability, as measured by beta, and it included electric companies that had few or no coal-fired assets.[151] Moreover, Minnesota Power criticized LPI for including companies in the comparison group based on their "senior secured" credit ratings, which it argues have less relevance to equity investors than "corporate" credit ratings.[152]

110. The most significant disagreement was in LPI's use of projected dividend growth rates in the DCF model. Both Minnesota Power and OES relied on projected earnings growth rates for their analyses.[153]

111. Finally, the LPI argued against any adjustment for flotation costs, suggesting that current stock prices already reflect such costs.[154] Minnesota Power and OES disagreed.[155]

112. Minnesota Power corrected the LPI analysis to account simply for the deficiencies in growth rate estimates and flotation adjustment.[156] These corrections increased the results from 9.86% to 10.9%.[157] In addition, Minnesota Power disqualified LPI's Methods 1 and 2, because they included companies whose projected growth rate was less than 1.00%, which would not be real growth because it is less than the rate of inflation.[158] Minnesota Power contended that LPI's recommendation would put Minnesota Power at a significant disadvantage in the competition for capital, could lead to a credit downgrading, and would add significant future costs to ratepayers.[159]

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[147] Ex. 29 at 48-50 (Hevert Rebuttal).
[148] *Id*. at 54.
[149] Id. at 11.
[150] *Id*. at 14-15.
[151] *Id*. at 16-17.
[152] *Id*. at 19-20.
[153] *Id*. at 21.
[154] Ex. 60 at 42 (Baudino Surrebuttal).
[155] Ex. 29 at 33 (Hevert Rebuttal); Ex. 77 at 23 and EA-33 (Amit Direct).
[156] Ex. 29 at 42-43 (Hevert Rebuttal).
[157] *Id*. at 43.
[158] *Id*. at 27 and 43.
[159] Ex. 30 at 30-31 (Cannell Rebuttal).

113. The Multi-Party Stipulation was achieved by adopting the OES recommendation of an ROE of 10.38%.[160] The range of DCF results for all three of the different proxy groups was from a low of 9.23% to a high of 12.06%.[161] The midpoint of that range is the 10.74% allowed by the Commission in the 2008 rate case.[162]

114. No party objects to the ROE of 10.38%. Given that range and the proximity of the 2008 Commission decision, the use of an ROE of 10.38% is fair to ratepayers and should be approved.

115. ***Cost of Debt.*** Minnesota Power originally proposed a cost of debt of 5.93%.[163] In rebuttal testimony, it revised that rate to 5.75% to reflect the actual cost of the Company's February 2010 debt issuance.[164] In addition, Minnesota Power agreed with the OAG that the debt costs should be updated to include the actual cost of the Company's next bond issuance, expected for mid-2010.[165]

116. Minnesota Power estimated the cost of variable rate debt of 2.67%.[166] Although recent rates were below 1.0%, as a result of unusual actions of the Federal Reserve, Minnesota Power maintained that the Federal Reserve actions could not be expected to continue indefinitely and the normal rate, such as that during the 2006-2007 timeframe, was 3.90%.[167]

117. OES agreed with Minnesota Power on all issues regarding long-term debt except variable rate debt. OES agreed that current market conditions were unusual, but asserted that the variable debt cost should be 0.65%.[168]

118. The LPI recommended that Minnesota Power's long-term debt cost be adjusted to reflect the actual cost of the new debt issue projected for mid-2010.[169] In addition, LPI recommended a 1% variable debt rate, recognizing that current rates were less but that rates potentially could increase by the end of the year.

119. The OAG agreed that Minnesota Power should update its long-term debt costs to reflect the actual cost of the debt issuance projected for June 2010. It recommended that the variable debt rate should be set at 0.59%.[170]

120. The Multi-Party Stipulation accepted the recommendations of all witnesses to reflect the actual costs of the new mid-year 2010 debt issuance.[171]

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[160] Ex. 108, Section 2 (Multi-Party Stipulation).
[161] Ex. 29 at 9 (Hevert Rebuttal).
[162] *2008 Rate Case Order* at 36-39 and Schedule 4.
[163] Ex. 31 at 22-23 (Stellmaker Direct).
[164] Ex. 32 at 1 (Stellmaker Rebuttal).
[165] *Id*. at 28.
[166] *Id*.
[167] *Id*. at 30-31.
[168] Ex. 80 at 31-32 (Amit Surrebuttal).
[169] Ex. 57 at 22 (Kollen Surrebuttal).
[170] Ex. 76 at 11, 16 (Smith Surrebuttal).
[171] Ex. 108, Section 2 (Multi-Party Stipulation).

Pursuant to that agreement, Minnesota Power reports that on June 10, 2010, it accepted bids on two series of First Mortgage Bonds: $30 million maturing on October 15, 2025, with a coupon rate of 4.90% and $45 million maturing on April 15, 2040, with a coupon rate of 5.82%, for a weighted coupon rate of 5.45%. The closing for these two series of bonds is scheduled for August 17, 2010, at which time the Company will execute the bond purchase agreement and issue the bonds.

121. The Multi-Party Stipulation accepted the recommendation of the LPI with regard to the variable debt rate, setting it at 1%.[172]

122. The OAG objects to this provision of the settlement, arguing that if the Settlement is accepted, the variable debt rate should be decreased to reflect actual 2010 rates.[173]

123. The issue at the hearing was how to best predict what would happen to the variable cost of debt during 2010, given the influence of the Federal Reserve in holding rates low and the potential for rates to rise before the end of the test year. There was a range of recommendations from 0.59% to 2.67%. The parties other than the OAG agreed that the 1% rate advocated by the LPI was a reasonable reflection of Minnesota Power's likely variable debt cost during the test year. This agreement is fair, reasonable, and supported by the record. The terms of the Multi-Party Stipulation would not allow for a revision of the 1% variable debt rate to an as yet unknown actual 2010 rate without potentially jeopardizing the entire agreement. The Administrative Law Judge concludes this provision of the agreement is reasonable and should be adopted.

124. As a result of the bond transaction in June 2010, and the agreement as to the variable debt rate, the Multi-Party Stipulation produces a long-term cost of debt for the test year of 5.56%.

125. ***Capital Structure.*** Minnesota Power recommended an equity ratio of 54.29%.[174] This recommendation is based on the use of a 13-month average common equity balance. It is lower than the equity ratio carried by ALLETE to support its credit rating (57.8% for year-end 2008, and 56.9% for the test year).[175] It is also below the equity ratio allowed in Minnesota Power's 2008 rate case (54.79%).[176]

126. OES recommended a lower equity ratio of 51.71%, based on the average of the equity ratios of the electric and combination comparison groups for 2008.[177]

127. In response, Minnesota Power maintained that an equity ratio of 51.71% would not sustain the Company's credit rating.[178] This equity ratio would result in an

[172] Ex. 108, Section 2 (Multi-Party Stipulation).
[173] OAG Initial Brief at 25.
[174] Ex. 31 at 2 (Stellmaker Direct).
[175] *Id*. at 26.
[176] *2008 Rate Case Order* at 32.
[177] Ex. 77 at 40-41 (Amit Direct).
[178] Ex. 32 at 4-5, 9 (Stellmaker Rebuttal).

adjusted debt ratio for Minnesota Power of 57.0%, well above (worse than) the ceiling recommended by S&P.[179]

128. The LPI accepted the Company's recommended equity ratio.[180]

129. The Multi-Party Stipulation incorporates the Company's proposed equity ratio of 54.29%. No party objected to this settlement.

130. In Minnesota Power's last rate case, the Commission approved the use of the Company's proposed equity ratio, in combination with the lower ROE recommended by the OES. The Commission noted the importance of maintaining the Company's bond rating, in light of its need to acquire significant capital for anticipated construction activity.[181] Those same concerns apply here; Minnesota Power expects to spend more than $500 million on capital projects in 2009 and 2010, which will require securing external capital.[182]

131. The Administrative Law Judge concludes the 54.29% equity ratio is fair and reasonable.

132. Based on the stipulated ROE, cost of debt, and equity ratios, Minnesota Power's overall weighted cost of capital for the test year pursuant to the Multi-Party Stipulation is 8.18%.

III. LP RATE DESIGN SETTLEMENT.

133. On May 18, 2010, Minnesota Power and LPI entered into a settlement agreement regarding certain rate design issues specific to the Large Power class.[183] In its initial filing, Minnesota Power had proposed to increase the minimum percentage of nominations that were take-or-pay to no less than 50% of the customer's full loads and to impose a non-uniform nomination charge in the Large Power service tariff. LPI objected, because these issues had historically been negotiated in Electric Service Agreements (ESAs), which are subject to approval by the Commission.[184]

134. Take-or-pay contracts require Large Power customers to pay a minimum level of compensation whether power is taken or not. OES supported the proposed increase in the Large Power minimum billing demand requirements, because these agreements function to cushion other rate classes from the risk of revenue loss from one large customer or class of customers.[185]

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[179] Ex. 32 at 8 (Stellmaker Rebuttal).
[180] Ex. 58 at 33 (Baudino Direct).
[181] *2008 Rate Case Order* at 32.
[182] Ex. 31 at 6-7 (Stellmaker Direct).
[183] Ex. 109 (LP Rate Design Settlement).
[184] Ex. 63 at 5 (Coleman Direct); Ex. 65 at 5 (Latendresse Direct).
[185] Ex. 91 at 5-7 (S. Peirce Surrebuttal).

135. The OAG also supported increasing the minimum billing demand requirements for the same reasons.[186]

136. In the LP Rate Design Settlement, Minnesota Power agreed to withdraw its proposals to (1) impose through changes to the *tariff* a minimum 50% take-or-pay commitment, rather than by individual contractual provisions; and (2) to eliminate from certain Large Power electric service agreements any ability to make non-uniform nominations during a nomination period.[187] In turn, LPI and the Company agreed that provisions dealing with take-or-pay commitment levels and the manner or method of making nominations during nomination periods would be addressed when each individual ESA is next amended.

137. OES does not object to the LP Rate Design Settlement, despite its support for making those changes through the tariff.[188]

138. The OAG objects to this settlement because it asserts that customers in other rate classes should be protected to the maximum extent possible from the risk associated with providing service to Large Power customers.

139. The LP Rate Design Settlement does not eliminate take-or-pay contracts, it simply provides for the continued negotiation of the terms in future ESAs, as opposed to imposing the terms through a tariff. OES and OAG will have the opportunity to review whether the negotiated terms appropriately protect the interests of other ratepayer classes when those agreements come before the Commission for review and approval.

140. This resolution reasonably and fairly addresses the concerns raised by the parties. The Administrative Law Judge recommends that the Commission approve it.

IV. OTHER RESOLVED ISSUES.

A. NOx Allowances.

141. In Minnesota Power's 2008 rate case, the Commission permitted the Company to return revenues and expenses from the sale and purchase of sulfur dioxide (SO2) emission allowance to ratepayers through the fuel clause adjustment rider.[189] The Company proposed the same treatment of nitrous oxide allowance revenues and expenses in the current rate case.[190] OES responded that determining the appropriate treatment of NOx allowances was unnecessary for this rate case, given that the Company did not include any NOx revenues or expenses in its test year budget.[191] The

[186] Ex. 73 at 6 (Lindell Surrebuttal).
[187] Ex. 109.
[188] Tr. 3:88 (S. Peirce).
[189] *2008 Rate Case*, Commission Order on Reconsideration at 3 (Aug. 10, 2009).
[190] Ex. 11 at 55 (Rudeck Direct).
[191] Ex. 94 at 25-27 (N. Campbell Direct).

Company agreed to defer a decision on this matter until the Company has occasion to purchase or sell NOx allowances.[192] The parties consider the matter resolved.

B. Base Compensation.

142. Minnesota Power initially proposed including $58,745,030 of employee base compensation in its 2010 test year budget, a figure that was increased to $59,871,699 in response to changes in the sales forecast and resulting revisions to the jurisdictional allocation factor.[193] OES initially objected to the Company's base compensation proposal because it reflected higher costs than in the 2008-2009 test year, even though the total Company had approximately 36 fewer employees in 2010.[194] OES filed direct testimony proposing to set 2010 base compensation at 2009 levels plus 3%.

143. In response, Minnesota Power provided evidence that while ALLETE as a whole had fewer employees, approximately 30 employees had moved from the unregulated to the regulated business as a result of the purchase and regulation of the Duluth Steam District #2.[195] Minnesota Power further explained that 2009 base compensation levels were frozen for management level employees, that the Company had implemented an unsustainable hiring freeze, and that the Company had discontinued its Results Sharing incentive compensation program, thereby artificially lowering 2009 base compensation to unsustainable levels.[196] Taking these factors together, Minnesota Power's proposed 2010 total base compensation plus incentive compensation is $1.4 million lower than the base compensation included in the 2008 rate case.[197] OES withdrew its objection and accepted the Company's adjustment as a result of the revised jurisdictional allocation factor, such that the matter is resolved.[198]

C. DC Transmission Line.

144. ***Purchase Price Adjustment.*** In Minnesota Power's initial filing, there was an apparent discrepancy between the Square Butte DC Line plant-in-service amount and the amount included in rate base. Believing that the Company had included a $72 million plant-in-service amount for the purchase of the DC Line in its schedules, OES proposed a rate base adjustment of $2.3 million to reflect the final, actual plant-in-service amount.[199] In rebuttal testimony, the Company explained that the net plant-in-service amount included in rate base was $63.968 million, which is very close to the actual amount of $63.949 million such that only minor adjustments of -$2,492 for Plant

[192] Ex. 12 at 50 (Rudeck Rebuttal).
[193] Ex. 37 at 7 (Carter Direct); Ex. 38 at 5 (Carter Rebuttal).
[194] Ex. 104 at 19 (Lusti Direct).
[195] Ex. 38 at 3-4 & Schedule 1 (Carter Rebuttal).
[196] *Id*. at 4-5.
[197] *Id*. at 5.
[198] Ex. 106 at 13 (Lusti Surrebuttal).
[199] *See generally* Ex. 94 at 3-12, and Schedule NAC-5 (N. Campbell Direct).

in Service and $16,453 for Accumulated Depreciation were necessary.[200] OES accepted that no downward adjustment is necessary.[201]

145. ***PPA Renegotiation Costs.*** The Company's initial rate case filing also included estimated external costs for the DC Line acquisition and renegotiation costs for the associated Square Butte power purchase agreement (PPA). Adjustments were made in rebuttal testimony to reflect actual costs. Minnesota Power noted that the actual acquisition costs were $1,195,453, an increase from the original cost estimate of $600,000, which required a $14,230 increase in the annual amortization and a $588,338 increase in rate base.[202] In addition, the $1,231,310 actual PPA renegotiation costs were higher than the $780,000 estimate, resulting in an increase of $26,548 in annual amortization and a $438,036 increase in rate base.[203] OES agreed with the adjustments, noting that the Company's responses to Information Requests clearly show the increase in the acquisition and renegotiation external costs.[204] This issue is therefore resolved.

146. ***Revenue and Expense Adjustments*.** The parties agree that adjustments are necessary to reflect the MISO Schedule 7 rates that were effective in January 2010.[205] The result was an $800,000 increase in operating revenue and a $500,000 decrease in operating expense.[206] Minnesota Power and OES consider this issue resolved.

D. Boswell 4 Depreciation.

147. Minnesota Power included in this case the adjustments to the remaining life and net salvage rate proposed for Boswell 4 in the depreciation docket that was pending at the time of its initial filing.[207] In both the depreciation docket and the rate case, OES objected to changing the net salvage rate of Boswell 4.[208]

148. On June 17, 2010, based on agreement between OES and Minnesota Power in the depreciation docket, the Commission adopted the recommendation not to change the net salvage rate for Boswell 4.[209]

[200] Ex. 49 at 9, and Schedule 1 at page 7 of 13 (Podratz Rebuttal). The actual in-service amount in rate base is further set forth in Schedule 1, page 7 of 13, at footnotes 2, 3, 5, and 6; *see also* Ex. 96 at 3 (N. Campbell Surrebuttal).
[201] Ex. 96 at 4 (N. Campbell Surrebuttal).
[202] Ex. 49 at 11 & Schedule 1 at page 9 of 13, upper section (Podratz Rebuttal).
[203] *Id*. at 11 & Schedule 1 at page 9 of 13, lower section; *see also id*., Schedule 2.
[204] Ex. 96 at 9 (N. Campbell Surrebuttal).
[205] Ex. 49 at 19-20, 38 (Podratz Rebuttal); Ex. 96 at 10 (N. Campbell Surrebuttal).
[206] *Id*.
[207] Ex. 34 at 9 (DeVinck Direct).
[208] Ex. 96 at 45 (N. Campbell Surrebuttal).
[209] *In the Matter of the Petition of Minnesota Power for Approval of Depreciation Certification*, Docket No. E015/D-10-223, Order (Jun. 29, 2010).

149. This change in the depreciation docket should be reflected in the rate case by reducing depreciation expense in the amount of $236,409 on the income statement and by making a similar reduction in accumulated depreciation in rate base.

E. MISO Schedule 16 and 17 Amortization.

150. The Company and OES agreed that the Commission's Order in the Company's 2008 rate case established that the amount of Midwest ISO (MISO) 16 and 17 costs to be recovered was $4,428,480.[210] Minnesota Power's initial rate case filing, however, included an additional $120,818 of deferred cost, amortized over three years at $40,270 per year, to account for the one-month delay in the implementation of interim rates in the 2008 rate case (August 1, 2008 instead of July 1, 2008).[211] To reflect only the amount of MISO 16 and 17 deferred costs specifically approved by the Commission, the Company proposed a reduction in the annual amortization totaling $40,270.[212] OES agreed, and the matter is resolved.[213]

F. Patient Protection and Affordability Care Act Taxes.

151. The Patient Protection and Affordability Care Act (PPACA) was enacted in March 2010, after Minnesota Power's initial filing. One effect of this legislation is to remove a tax deduction for retiree health costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare D coverage. The result is an increase in Minnesota Power's federal taxes, such that the company incurred a one-time $4 million income tax expense in the first quarter of 2010. In rebuttal testimony, Minnesota Power proposed to refer this issue to a separate docket so that the issue can be more fully investigated and a consistent regulatory treatment determined.[214]

152. OES initially opposed this suggestion on several grounds, believing that Minnesota Power was seeking to establish deferred accounting treatment in this case.[215] Minnesota Power clarified that it is not asking the Commission to decide the amount or method of recovery of this tax expense in this rate case or to grant deferred accounting. The Company and OES subsequently agreed that the matter is best addressed outside this rate case, in a separate miscellaneous docket, where the amount, recovery, amortization period, and other matters affecting treatment of the PPACA tax can be addressed.[216]

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[210] Ex. 49 at 23 (Podratz Rebuttal); Ex. 96 at 43 (N. Campbell Surrebuttal).
[211] Ex. 49 at 23, 38 (Podratz Rebuttal).
[212] Ex. 49 at 23, 38 (Podratz Rebuttal).
[213] Ex. 96 at 43 (N. Campbell Surrebuttal)
[214] Ex. 35 at 2-3 (DeVinck Rebuttal).
[215] Ex. 96 at 42-43 (N. Campbell Surrebuttal).
[216] *See* Joint Proposed Findings of Fact on Resolved Issues at ¶¶ 79-82 (efiled July 14, 2010).

G. CCOSS/Marginal Energy Study in Next Rate Case.

153. OES proposed that Minnesota Power be required to prepare a marginal class cost of service study (CCOSS) in its next case to provide additional data for the Commission in designing efficient rates.[217] Minnesota Power objected to the cost of preparing such a study in addition to an embedded CCOSS, as well as the complexity of reconciling the two studies.[218] The Company proposed, however, to provide a marginal energy cost study in its next rate case, as that study would still aid the Commission in estimating the differential in setting peak and off-peak rates.[219] OES accepted this suggestion.[220]

H. Fuel and Purchased Energy (FPA) Rider.

154. OES proposed that the Company amend provision (h) of its proposed Rider for Fuel and Purchased Energy Adjustment (FPE Rider), also known as Fuel Clause Adjustment (FCA) rider, to reflect that all MISO costs and revenues would flow through the rider as required by Commission Orders generally, rather than referring to any specific or individual Order.[221] The Company agreed, and filed a revised FPE Rider.[222] OES also noted that the Company's FPE rider language related to NOx allowances must be deleted to reflect that this issue will be deferred until the Company anticipates making allowance purchases or sales.[223] The Company agreed to make the change in its final rate compliance filing.

I. CIP and Conservation Cost Recovery Charge (CCRC).

155. Minnesota Power proposed recovery of $4.6 million in Conservation Improvement Program (CIP) expenses, along with allocation of CIP expenses on a per-unit-of-energy basis and a rate design using a per-kWh rate instead of the current percentage of revenue methodology.[224] OES agreed, and no other party objected.[225] OES also agreed with the Company's base cost of conservation calculation methodology, but recommended updating the final conservation cost recovery charge (CCRC) based on the final test year sales levels approved by the Commission.[226] Minnesota Power agreed to recalculate the CCRC at the end of the case, based on the test year energy sales approved by the Commission.[227]

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[217] Ex. 82 at 14-15 (Ouanes Direct).
[218] Ex. 42 at 3 (Shimmin Rebuttal).
[219] *Id*. at 3.
[220] Ex. 83 at 3-4 (Ouanes Surrebuttal).
[221] Ex. 82 at 6 (Ouanes Direct).
[222] Ex. 25 at 19 (Seeling Rebuttal); Ex. 83, Schedule SO-S-2 (Ouanes Surrebuttal).
[223] Ex. 82 at 5 (Ouanes Direct).
[224] Ex. 47 at 44-46 (Podratz Direct).
[225] Ex. 102 at 12-13 (Davis Direct).
[226] *Id*. at 13.
[227] Ex. 49 at 27 (Podratz Rebuttal).

J. General Service Monthly Charge.

156. Minnesota Power initially proposed increasing the General Service class monthly service charge from $10.50 to $13.30.[228] OES and OAG objected to any increase, noting the substantial increase of the charge from $3.81 to $10.50 in the Company's last rate case.[229] Minnesota Power agreed that the General Service class experienced a large increase in the last rate case and accepted the OES and OAG recommendations to leave the General Service customers' monthly service charge at $10.50.[230]

157. This agreement should also affect service charges for Commercial Controlled Access and Municipal Pumping Service, which are proposed to match the General Service monthly service charge.[231]

K. Interest Synchronization.

158. OES noted that it is necessary to make an interest synchronization adjustment whenever the Company's weighted cost of debt, test year rate base, or operating income are adjusted.[232] The Company agreed to recalculate the interest synchronization adjustment following issuance of the Commission's final order.[233]

L. Cash Working Capital.

159. The Company provided a calculation of cash working capital in its initial rate case filing, based upon the Company's proposed rate base, revenues, expenses, and capital structure. In direct testimony, OES recommended adjustments to cash working capital to reflect OES's proposed adjustments at that time.[234] The Company agreed that cash working capital will need to reflect the Company's financial position at the end of the rate case and agreed with the calculation methodology.[235] Accordingly, cash working capital should be updated at the end of the case based on the parties' agreed methodology, once the Company's final rate base, revenues, expenses, and capital structure are known.

M. Foundry/Forging and Melting Tariff.

160. Foundry/Forging and Melting industrial customers are among the largest customers in Minnesota Power’s Large Light & Power customer class. Such customers typically have relatively low load factors. Minnesota Power proposed a tariff that would give these customers an interruptible demand charge discount and subject their energy use to price recalls of up to 200 hours per year. During recall periods, a customer could

[228] Ex. 47 at 60 (Podratz Direct).
[229] Ex. 88 at 19-20 (S. Peirce Direct); Ex. 74 at 68 (Smith Direct).
[230] Ex. 49 at 35-36 (Podratz Rebuttal).
[231] Ex. 49 at 35-36 (Podratz Rebuttal).
[232] Ex. 104 at 22 & Schedule DVL-8 (Lusti Direct).
[233] Ex. 49 at 23-24 (Podratz Rebuttal).
[234] Ex. 104 at 11 (Lusti Direct).
[235] Ex. 49 at 12 (Podratz Rebuttal).

choose to curtail their energy usage or pay a higher price based on the incremental cost of energy at the time. The proposed tariff would give customers an alternative pricing structure, while the price-recall provision would give Minnesota Power the ability to reduce its load during system peak periods.[236] The OES supported the proposed tariff.[237]

N. Time-of-Use Rate for LLP Customers.

161. Minnesota Power currently offers only a flat-rate energy charge to Large Light & Power customers, which applies to all energy usage, regardless of the time of day that the energy is used. Enbridge Energy is a pipeline company that takes service from Minnesota Power's Large Light & Power tariff. Enbridge submitted public comments requesting that the Company implement a time-of-use (TOU) rate for LLP customers.[238] OES supported Enbridge's request, because a TOU rate would more closely align rates with costs incurred for energy, provide more accurate price signals, and encourage energy savings and load shifting.[239] Minnesota Power concurred, and proposed that the Company submit a TOU tariff proposal within 30 days of the final effective date for rates in this case.[240] The OES agreed with this proposal.

O. Lighting Tariff.

162. Minnesota Power proposed to close Option 3 to new customers, increase the rates for various types and sizes of lamps, add new lamp types and sizes, and delete rate codes associated with the rate code consolidation approved by the Commission in the 2008 Rate Case.[241] OES agreed that this proposal is reasonable.[242]

163. In a written comment, the City of Duluth objected to phasing out of the Option 2 street lighting rate. Option 2 has been closed to new customers for some time, and Minnesota Power proposes in this case to close Option 3 to new customers; but it does not appear from the record that Minnesota Power is proposing to eliminate Option 2 at this time.[243]

P. Miscellaneous Tariff Changes.

164. Minnesota Power proposed to revise its Electric Service Regulations to incorporate current references to Minnesota Statutes and Rules, provide updated

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[236] Ex. 48 at 61 (Podratz Direct). Minnesota Power also proposed some changes to Municipal Pumping and Large Power rate schedules, to which no party objected. *See* Ex. 47 at 60, 65 (Podratz Direct).
[237] Ex. 87 at 20 (S. Peirce Direct).
[238] *Id*. at 21 and SLP-7.
[239] Ex. 87 at 21 & SLP-7 (S. Peirce Direct).
[240] Ex. 49 at 36 (Podratz Rebuttal).
[241] Ex. 48 at 62-64 (Podratz Direct).
[242] Ex. 87 at 24 (Peirce Direct).
[243] Ex. 48 at 62 (Podratz Direct).

contact information, and delete outdated provisions.[244] OES supported the proposed changes.[245]

V. DISPUTED RATE BASE ISSUES.

A. Square Butte Transmission Line.

165. In May 2009, Minnesota Power sought approval from the Commission to (1) purchase from Square Butte Cooperative a 250 kV direct current (DC) transmission line running from Square Butte substation in Center, North Dakota, to Minnesota Power's Arrowhead substation near Duluth; and (2) restructure its power purchase agreements with Square Butte Cooperative for coal-fired generation transmitted over the line. Minnesota Power stated that it intended to gradually replace the coal-fired power with wind power from North Dakota wind facilities to meet its renewable energy obligations under Minn. Stat. § 216B.1691. The Commission approved the Petition after a contested case hearing, subject to certain conditions.[246]

166. In its compliance filing in that docket, Minnesota Power's summary of accounting entries for the transmission line showed a total purchase price of $69.7 million, which included $2.84 million in Inventory and $2.89 million in Construction Work in Progress (CWIP). The compliance filing also showed $1.19 million in acquisition costs.[247] The total plant in service was identified as $103.5 million.[248]

167. In Minnesota Power's initial filing in this rate case, which was made before the compliance filing in the above docket, the Company estimated the purchase price at $72 million, including inventory and CWIP, and indicated that test year rate base included:

Purchase Price:	$72 million
50 MW DC terminal upgrades:	$ 2.56 million
Acquisition costs:	$ 1.19 million
Replacement of HVDC base system:	$ 5.24 million
Total:	$81 million[249]

168. OES compared this claim to the compliance filing and questioned the discrepancy in the purchase price. OES recommended that the purchase price be adjusted downward by $2.3 million, to the $69.7 million reflected on the compliance

[244] Ex. 48 at 66-68 (Podratz Direct).
[245] Ex. 87 at 24 (Peirce Direct).
[246] *In the Matter of Minnesota Power's Petition to Purchase Square Butte Cooperative's Transmission Assets and for Restructuring Power Purchase Agreements from Milton R. Young 2 Generating Station*, Docket No. E015/PA-09-526, Order Granting Petition with Conditions (Dec. 21, 2009).
[247] Ex. 94 at 6 (N. Campbell Direct); Ex. 49 at MP Schedule 1, page 3 of 13 (Podratz Rebuttal).
[248] Ex. 49 at MP Schedule 1, page 3 of 13 (Podratz Rebuttal). The plant in service amount ($103.5 million), minus accumulated depreciation ($39.5 million), plus Inventory ($2.84 million) and CWIP ($2.89 million) equals the total purchase price of $69.7 million.
[249] Ex. 11 at 44 (Rudeck Direct).

filing. It also questioned whether the $2.56 million for terminal upgrades should be included in rate base, because the Company had indicated in discovery that this amount had been removed from rate case revenue requirements and would be recovered through a rider mechanism (the future Bison 1 Renewable Rider).[250]

169. In rebuttal, Minnesota Power provided testimony demonstrating that the purchase price amount included in rate base was $63.968 million, compared to the actual cost of $63.949 million. Minnesota Power also stated that, in reviewing the compliance filing and its initial filing, the Company determined that it had failed to include in the purchase price the amounts for Inventory ($2.84 million) and CWIP ($2.89 million), which would have brought the final purchase price to the $69.7 million reflected in the compliance filing.

170. OES accepted the adjustment in purchase price from the estimated $63.968 to the actual $63.949 million; that issue has been resolved as indicated in Finding 144. It refused to accept, however, the proposed adjustment to add Inventory and CWIP amounts. It contended that these were "new" costs (even though these costs were included in the $69.7 million figure that OES had advocated for in its direct testimony, based on the compliance filing) and asked the Administrative Law Judge to strike this portion of Minnesota Power's rebuttal testimony from the record. It also maintained that Minnesota Power had failed to show that the terminal upgrade cost had been removed from rate base.[251]

171. During the hearing, Minnesota Power agreed to withdraw the proposal to add $2.84 million in Inventory to rate base.[252]

172. The remaining disputed issues, therefore, are whether the Company should be allowed to add $2.89 million to the purchase price for CWIP, and whether the claimed $2.56 million in terminal upgrade cost has already been removed from rate base (as claimed by Minnesota Power) or should be subtracted (as advocated by OES).

173. ***CWIP*.** The parties have agreed that Minnesota Power's initial testimony (that $72 million, including inventory and CWIP, had been added to rate base to reflect the purchase price) was in error. OES has accepted that the actual amount added to rate base is the difference between actual plant in service and accumulated depreciation, or $63.949 million. This figure is consistent with the compliance filing in the E015/PA-09-526 Docket.

174. It is clear that this figure does *not* include the CWIP amount that is also reflected on the compliance filing. Minnesota Power has provided information breaking down its CWIP schedule by project number and name, and the Square Butte Transmission Line project (No. 103400) does not appear on the schedule. In fact, the

[250] Ex. 94 at 6-8 (N. Campbell Direct).
[251] Ex. 96 at 3-9 (N. Campbell Surrebuttal). The ALJ denied the motion to strike this testimony at the outset of the hearing, but offered OES additional time to investigate and respond to it. Tr. 1:10. OES declined this offer. Tr. 3:146.
[252] Tr. 2:167-68 (Podratz).

total amount of CWIP claimed for all transmission in 2010 is $1.25 million, which is less than half the CWIP claimed for the purchase of this particular transmission line.[253] That figure ($1.25 million), in turn, appears as the total CWIP in rate base in the Company's initial filing.[254]

175. OES further argued that CWIP is allowed to be included in rate base prior to the actual in-service date because allowance for funds used during construction (AFUDC) is also recorded on the income statement as an expense.[255] Based on this, OES argues that the Company did not provide information showing that an offsetting AFUDC expense was included.

176. During the hearing, Minnesota Power offered testimony that the CWIP balance was transferred from the previous owner (Minnkota Power) to Minnesota Power at the time of the closing on December 31, 2009. At that time, the CWIP was actually for plant that was in service; it was not for construction prior to the date of plant-in-service. Accordingly, Minnesota Power moved the CWIP balance to plant- in-service without recognizing AFUDC.[256]

177. OES argues that Minnesota Power's evidence should be disregarded based on the Commission's Statement of Policy on Updating Test Year Information (Jun. 14, 1982). The policy provides that, when faced with the question on how to update future test year projections, the Commission will consider the most recent data to the extent the new evidence can be substantiated by the utility; is admitted within a reasonable time in the course of the proceedings to allow all parties opportunity to obtain in-depth familiarity with the new data, to cross-examine the utility's witnesses regarding it, and to offer such evidence in surrebuttal as necessary. The Commission may disregard new evidence if there is insufficient time to allow for adversarial testing of the data.[257] OES also argues that denial of CWIP cost at this time would not preclude Minnesota Power from requesting recovery in a future rate case.[258]

178. The record reflects that this proposed revision is not a matter of updating a test year projection with more recent data; it is a matter of correcting an entry regarding a past transaction that contains an obvious error. The Company did not "delay" its correction for any period of time; the error was corrected as soon as OES pointed it out. The position of OES that the CWIP figure is a "new" number and that it was deprived of the opportunity to investigate the legitimacy of the number through discovery is unfounded. The Administrative Law Judge does not believe OES was prejudiced in any way in the development of the record concerning this issue. OES had the opportunity to examine the compliance filing; in fact, the OES brought the compliance filing to Minnesota Power's attention in its direct testimony, and it has accepted Minnesota

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[253] Ex. 50 at MAP Rebuttal Schedule 1 at 13 (Podratz Rebuttal).
[254] Ex. 6 at Rate Base Schedule 2-1, Transmission Column, Row 2 (Vol. 4 Work Papers).
[255] Ex. 96 at 8 (N. Campbell Surrebuttal).
[256] Tr. 2:168 (Podratz).
[257] Attachment to OES Initial Brief.
[258] *See* OES Proposed Finding No. 98 (July 14, 2010).

Power's evidence that only $63.949 million was added to rate base in the initial filing. In addition, OES declined the opportunity to investigate the matter further.

179. Moreover, OES's refusal to accept the inclusion of $2.89 million in CWIP is inconsistent with its initial advocacy on this issue, which recommended that the Commission set the purchase price at $69.7 million, the number reflected in the compliance filing. The Administrative Law Judge concludes that Minnesota Power has established that $2.89 million in CWIP should be added to the purchase price of the transmission line to correct an error in the initial filing.

180. ***Terminal Upgrades.*** The issue regarding terminal upgrades also arose as a result of the same erroneous testimony by a Minnesota Power witness as to matters included in rate base. As noted above, the witness (Rudeck) indicated that $2.5 million in terminal upgrade costs had been included in rate base, while the Company's discovery responses indicated that this amount had been excluded from rate base and would be included in a future rider.[259]

181. In rebuttal, Minnesota Power explained that this characterization was in error and that the witness (Rudeck) should have indicated only that this amount was included in a capital budget.[260]

182. Mr. Rudeck testified only as to Minnesota Power's planned capital investment in the transmission line; at the time his testimony was filed, the Commission had not yet approved the purchase. A different witness (Podratz) sponsored the rate base summary and other financial schedules. The record reflects that the Rudeck testimony characterizing both the cost of the upgrade project and its inclusion in rate base was inaccurate.

183. Minnesota Power's initial filing and the direct testimony of witness Podratz showed that $15.11 million in transmission plant was removed from rate base for anticipated rider projects.[261] In response to OES questions about how the transmission line terminal upgrade costs were to be recovered, Podratz provided an additional schedule that broke down this $15.11 million figure by project. The schedule includes $2.1 million in projects that also appear on Minnesota Power's capital budget schedule for the DC transmission line.[262]

184. Minnesota Power's schedules are consistent in showing that $15.11 million in transmission plant was removed from rate base for rider projects, and its evidence establishes that $2.1 million of the $15.11 million figure is for projects associated with terminal upgrades for the transmission line. Based on this evidence, the Administrative Law Judge finds that Minnesota Power has established that the

[259] Ex. 11 at 44 (Rudeck Direct); Ex. 94 at 6-8 (N. Campbell Direct).
[260] Ex. 49 at 11-12 (Podratz Rebuttal); Tr. 2:168-69.
[261] Ex. 6, Rate Base, RB-7, Transmission column, Row 4 (Vol. 4 Work Papers); Ex. 48 at Schedule 2, pages 1 and 2 (Podratz Direct) (reflecting $15.11 million in transmission removed to cost recovery riders.)
[262] Ex. 50 at Rebuttal Schedule 1, page 8 (Podratz Rebuttal); Ex. 6, Rate Base, RB-6-5, 50 MW DC Line Upgrade (Vol. 4 Work Papers).

terminal upgrade costs were removed from rate base and accordingly recommends that the Commission make no further adjustment to the Company's rate base calculation.

B. Boswell 4—Timing of Plant Additions.

185. Minnesota Power expects that its capital improvements to Boswell 4 in the amount of $86 million will be placed in service between March and December 2010. Most of these projects will be placed in service on or after September 30, 2010.[263] The Company accounted for these investments by using a simple average of the plant-in-service balances as of December 31, 2009, and December 31, 2010.[264] This method assumes that all plant additions in the test year occur at the midpoint of the test year. The use of this method to account for the improvements resulted in a $43 million addition to rate base in the test year.[265]

186. LPI (and no other party) objected to using this method to add plant in service for the Boswell 4 projects, arguing that Minnesota Power should have used a weighted monthly average to ensure that no more than three months of plant in service is recognized for the test year.[266] LPI contend that, because Minnesota Power will earn a return on AFUDC through September 30, 2010, and because use of the simple average balance method will result in a return for essentially six months of the year, an adjustment is necessary to prevent over-earning on the overlapping period. The proposed adjustment would reduce recovery of Boswell 4 capital investment by $21.883 million and would reduce the revenue requirement by approximately $2.9 million.[267]

187. The Commission's rule requires a utility to include in its rate base schedules the Company's "proposed rate base" and "the unadjusted average rate base for the most recent fiscal year and . . . the projected fiscal year."[268] In addition, the utility is required to provide total utility and the proposed jurisdictional rate base amounts for the test year, including the adjustments, if any, used in determining the proposed rate base.[269]

188. In situations in which a plant addition is completed during a test year, the Commission has consistently chosen to use a simple average of beginning and ending plant balances. This method is relatively straightforward, and will sometimes favor utilities while sometimes favoring the ratepayers, depending on when any given project goes into service.[270] The method acknowledges that even if a project is only in service for a portion of the test year, it will remain in service for the entire following year.[271] The

[263] Ex. 55 at 22 (Kollen Direct); Tr. 1:146.
[264] Ex. 49 at 13 (Podratz Rebuttal).
[265] Ex. 56 at 21 (Kollen Direct).
[266] *Id*. at 24; Ex. 57 at 18-19 (Kollen Surrebuttal).
[267] Ex. 55 at 23 and LK-7 (Kollen Direct).
[268] Minn. R. 7825.4000 A.
[269] Minn. R. 7825.4000 B.
[270] Ex. 49 at 13 (Podratz Rebuttal).
[271] Ex. 12 at 45-46 (Rudeck Rebuttal).

weighted method proposed by LPI would require some adjustment to reflect that, after the test year, the plant would be in service for all months of subsequent years.[272]

189. LPI has not articulated why these investments should be given different treatment than all other rate base additions during the test year, except to say that these are significant investments. The Administrative Law Judge cannot recommend that one method should be used for some investments, but a different method should be used for others, if the investments are large enough. The Administrative Law Judge accordingly recommends that the Commission approve Minnesota Power's use of the average plant-in-service method used to account for the additions to Boswell 4. If an adjustment is appropriate, perhaps the return on AFUDC could be limited to the period from January through June 2010, to eliminate the overlap in returns.

C. Boswell 4—Capital Adjustment.

190. Boswell 4 is Minnesota Power's largest generating facility. The Company provided evidence that substantial capital investments will be made in the test year to reduce emissions, improve efficiency, and maintain reliability of the facility for its intended duty cycle as defined in the Company's integrated resource plan.[273]

191. MCEA filed no testimony in this matter but asserted for the first time in its initial brief that Minnesota Power's planned investment in Boswell 4 should be entirely disallowed, because federal regulation of greenhouse gases and coal combustion residue is "imminent" and will severely negatively impact the economics of running traditional coal-fired power plants.[274] MCEA argued that the Company has failed to demonstrate that it is prudent or reasonable "to saddle ratepayers with an estimated $75 million in capital investment to extend the operations of Boswell Unit 4 until 2035."[275]

192. MCEA's argument is speculative and lacks a basis in the evidentiary record. The record reflects that these are maintenance projects intended to keep the facility functioning and environmentally compliant until the end of its service life. The Commission would make any decisions about extending the useful life of the facility in an Integrated Resource Planning Docket, not in this rate case.[276] The Administrative Law Judge recommends that the Commission reject the proposed adjustment to rate base.

[272] Ex. 12 at 46 (Rudeck Rebuttal).
[273] Ex. 11 at 15-17 (Rudeck Direct); Tr. 1:100-01 (Rudeck).
[274] MCEA Initial Brief at 4.
[275] *Id*. at 2.
[276] Ex. 11 at 15-17 (Rudeck Direct); Tr. 1:100-01 (Rudeck).

VI. DISPUTED INCOME STATEMENT ISSUES.

A. Pension Expense.

193. Minnesota Power's employee retirement income benefits come from two primary sources: (1) a defined contribution (DC) plan that has features of both an Employee Stock Ownership Plan and a 401(k) retirement savings account; and (2) defined benefit (DB) pension plans. The Company provides contributions to the DC Plan in the form of ALLETE Common Stock and employee cash contributions. The DB Plans are funded with Company contributions.[277]

194. Beginning in 2006, the Company applied a "soft freeze" to non-bargaining unit employee pension benefits, so that future service was no longer counted for purposes of calculating those pension benefits. Instead, the Company provides additional matching contributions to those employees' DC Plan accounts in the form of ALLETE Common Stock.[278]

195. Also in 2006, the Company implemented a "hard freeze," closing the DB Plans to newly-hired non-bargaining unit employees and substituting the DC Plan, funded through Company contributions of ALLETE Common Stock and employee cash contributions.[279]

196. Minnesota Power's actual pension expense for 2005-2009 is as follows:

2005	2,718,437
2006	4,299,082
2007	457,165
2008	(554,057)
2009	293,312[280]

197. For the 2010 test year, Minnesota Power included $1.968 million (Minnesota jurisdictional) in estimated pension costs. This increase in cost was largely the result of investment losses incurred by assets held in the pension trust. In 2008, the market value of pension assets of ALLETE dropped by 29%.[281]

198. OES objected to including in the test year $1.968 million in pension cost. OES provided three reasons in support of its objection. First, it argued that pension expense was historically volatile and should be normalized to reflect expense actually incurred over time. Second, OES argued it was not appropriate to set pension expense

[277] Ex. 37 at 28 (Carter Direct).
[278] *Id*. at 30.
[279] *Id.*
[280] Ex. 93 at NAC-12 (N. Campbell Attachments).
[281] Ex. 37 at 31 (Carter Direct).

in rates based on a point in time when the value of the pension fund was lower than normal or average, without the benefit of improvements in financial markets experienced in 2009 and 2010. Third, OES argued that the discount rate used to estimate pension expense (6.75%) was selected by Minnesota Power, not by an actuary independent of the Company. OES recommended that pension expenses be normalized over the five-year period from 2005-2009, since these are the most recent years with actual pension expense. This calculation results in an average pension expense of $1.442 million, a decrease of $ 525,547 to Minnesota Power's initially proposed pension expense in the test year.[282]

199. In its rebuttal testimony, Minnesota Power provided updated actual 2010 pension costs in the amount of $2.769 million, largely as a result of the decline in the discount rate (to 5.81%).[283] Minnesota Power maintains it is appropriate to increase its initial test year expense by $800,531 to reflect actual test year expense.

200. OES argues that pension costs have gone up and down and are not trending upward. It continues to recommend that pension expense be averaged over the five-year period from 2005-2009, as indicated in its direct testimony.[284]

201. With regard to OES's first argument, that pension expense has been volatile and should therefore be normalized, the record reflects something other than unpredictable volatility. The parties agree that the increased expense for the 2010 test year is a result of recognizing the substantial market losses sustained during the recent economic downturn. Although this may not yet be a "trend" because it happened so recently, these investment losses are expected to increase pension expense over the next several years because they are amortized over the average remaining future service of plan participants, which is about 12 years.[285] Neither the Company nor its actuary foresees a material decline in costs in coming years.[286]

202. Minnesota Power's actuary uses a "smoothing method" under pension accounting rules that is designed to reduce pension expense volatility, or to "normalize" pension expenses over a period of years. Asset gains and losses are phased in over a five-year period. The smoothed asset value is also used in the amortization of the total outstanding cumulative gains and losses experienced by the plan. The smoothed asset value as of December 31, 2009 was $400.3 million, as compared to the fair market value of plan assets of $327.6 million on that date.[287] Minnesota Power has established that it would not be appropriate to make a further "normalizing" adjustment by averaging pension expense over time to reflect changes in asset value.

203. Generally accepted accounting principles require companies to select certain assumptions for their actuaries, including the long term rate of return and the

[282] Ex. 94 at 28-33 (Campbell Direct).
[283] Ex. 38 at 6 (Carter Rebuttal).
[284] Ex. 96 at 25-31 (N. Campbell Surrebuttal).
[285] Ex. 37 at 31 (Carter Direct).
[286] Ex. 38 at 6-7 (Carter Rebuttal).
[287] *Id*. at 7-8.

discount rate. The discount rate is used to discount the cost of future benefits back to today's cost level. The higher the discount rate, the lower the current expense level, and vice versa.[288]

204. Since September 2007, the Company has had a policy of using the Citigroup Pension Discount Curve in effect at the end of the year to establish the discount rate.[289] Its actuary conducts a "Yield Curve Analysis" to adjust the rate for projected cash flows to match ALLETE's pension plan characteristics. It also recommends an upper limit for the discount rate, beyond which the actuary would express no opinion on the reasonableness of the assumption.[290] The assumptions the Company selects are independently verified by the actuary (Mercer) and the Company's auditors (Pricewaterhouse Coopers).[291]

205. In 2007, the Citigroup Yield Curve produced a discount rate of 6.25% for ALLETE; the upper limit established by the actuary was 6.31%; and the Company selected a discount rate of 6.25%. In 2008, the Citigroup Yield Curve produced a rate of 6.12%; the upper limit established by the actuary was 6.21%; and the Company selected a discount rate of 6.12%. In 2009, the Citigroup Yield Curve produced a discount rate of 5.81%; the actuary's upper limit was 5.92%; and the Company selected a discount rate of 5.81%.[292]

206. OES argues the monthly Citigroup Pension Discount Curve is too volatile for use in setting pension expense. It also argues that the discount rate for the first three months of 2010 has been trending upward, which would result in a decrease in pension expense if updated to the current discount rate.[293]

207. Before it used the Citigroup Pension Discount Curve, ALLETE selected discount rates based on other indices. The Moody's Aa Index for December 31, 2008, would have produced a discount rate of 5.62%, and the Citigroup Pension Liability Index would have been 5.87%.[294] The Company's use of the Citigroup Pension Discount Curve resulted in a higher discount rate (6.12%) and lower overall pension expense than if these other indices had been used. On December 31, 2009, the Moody's Aa Index would have produced a discount rate of 5.57%, and the Citigroup Pension Liability Index a rate of 5.96%.[295] The Company's use of the Citigroup Yield Curve at 5.81% is between these two figures.

208. There is no evidence that Minnesota Power has manipulated the pension discount rate to the disadvantage of ratepayers; that Minnesota Power has selected an unusually volatile index for establishing pension expense; or that pension expense will

[288] Ex. 38 at 8-9 (Carter Rebuttal).
[289] *Id*.
[290] Ex. 39 (Mercer letter of January 10, 2010).
[291] Ex. 38 at 9 (Carter Rebuttal).
[292] Ex. 39.
[293] Ex. 96 at 28 (Campbell Surrebuttal).
[294] Ex. 39.
[295] *Id*.

likely be lower for the years in which rates set in this case will be in effect. The fact that discount rates may have changed since December 31, 2009, is not determinative; the plan required a measurement date of December 31, 2009. The Administrative Law Judge recommends that the Commission allow pension expense of $2.769 million in the test year, reflecting the Company's actual test year pension costs.

B. OPEB Expense.

209. The Company initially included an estimate of $6.216 million (revised Minnesota jurisdiction) in other post-employment benefit (OPEB) costs in its 2010 test year budget.[296] No party objected to this initial expense estimate in direct testimony.

210. The Company requested an upward adjustment in test year OPEB expense in its rebuttal testimony to reflect actual expense for 2010 in the amount of $7.659 million.[297]

211. The primary cause of the increase was the same change in discount rate that affected calculation of pension expense (from 6.75% used to calculate the estimated amount in mid-2009, to 5.81% used to calculate the actual expense at the end of 2009).[298]

212. OES opposed only the amount of the proposed increase in OPEB ($1.44 million), and it moved to strike this testimony from the record. As indicated above, the Administrative Law Judge denied the motion to strike but offered OES the opportunity to take additional time to respond to this information.[299] OES declined the opportunity.

213. In surrebuttal, OES objected to recognizing the increased amount of OPEB expense for the same reasons stated above with regard to pension expense.[300] OES also questioned whether the Company could justify continuing to include OPEB in future rate cases. While OES did not recommend complete denial of OPEB costs in this case, it did recommend that the Commission order the Company to demonstrate why ratepayers should pay OPEB costs in future cases. In support of this argument, OES points to the fact that Xcel Energy voluntarily made changes to its retiree health plan to reduce these benefits some years ago.[301]

214. The record reflects that, although OES anticipated the discount rate issue with regard to pension expense, it did not anticipate that the same change would impact OPEB expense, and it was taken by surprise when Minnesota Power filed its rebuttal testimony reflecting the $1.44 million increase. Although the report was provided to

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[296] Ex. 37 at 26 (Carter Direct); Ex. 38 at 10 (Carter Rebuttal).
[297] Ex. 38 at 10 (Carter Rebuttal).
[298] *Id.*
[299] The record reflects that Minnesota Power received the actuarial report at the end of January 2010; it was then sent to the Company's external auditors. It was provided to OES on March 24, 2010, as a supplemental response to a previous information request. *See* Affidavit of Elizabeth M. Brama (May 13, 2010), filed in response to OES Motion to Strike Certain Rebuttal Testimony.
[300] Ex. 96 at 33-34 (N. Campbell Surrebuttal).
[301] *Id.* at 33-35.

OES before the rebuttal, the Company did not make clear that it intended to seek the increase in OPEB expense until rebuttal testimony was filed shortly before the hearing. The Administrative Law Judge concludes that OES was prejudiced in its ability to develop this issue due to the circumstances under which it was disclosed.

215. The Administrative Law Judge consequently recommends that the Commission establish OPEB expense in the amount of $6.216 million, as Minnesota Power initially proposed, and decline to accept the additional $1.44 million in OPEB expense for the 2010 test year, as advocated by OES.

C. Incentive Compensation—Annual Incentive Program.

216. The Company has a base compensation program, a long-term incentive program, and an annual incentive program (AIP).

217. The parties have agreed that the amount of base compensation to be included in the test year budget is $59,871,699.[302]

218. In the last rate case, the Commission approved costs for two different incentive compensation programs; the Results Sharing program ($3.7 million) and the Annual Incentive Program (AIP) (approximately $870,000). The Commission limited the Results Sharing program to 5% and the AIP to 20% of base compensation and adopted a refund mechanism under which incentive compensation recovered in rates but not paid to employees is refunded to ratepayers. The Commission disallowed the inclusion of the Company's Long Term Incentive Program in rates, because it allowed too wide a range in compensation levels for top management employees, and its focus on corporate earnings benefited shareholders more than ratepayers.[303]

219. All bargaining unit, non-bargaining unit, and management employees participated in the Results Sharing program. The Company discontinued the Results Sharing program in August 2009, retroactive to the beginning of 2009. It increased the base compensation of non-management employees. For management employees, it shifted 5% of the Results Sharing incentive to the AIP. These management employees received no base pay adjustment in 2009.[304]

220. In this case, Minnesota Power proposes a test year budget of $1,713,430 for AIP expense.[305] It would limit the incentive to 20% of base compensation and include a tracking mechanism so that ratepayers would be refunded any AIP incentive compensation not awarded to employees.

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[302] *See* Finding Nos. 142 and 143.
[303] *2008 Rate Case Order* at 43-44.
[304] Ex. 37 at 13-14 (Carter Direct).
[305] Ex. 38 at 5 (Carter Rebuttal).

221. Consistent with the Commission's direction in the last rate case, Minnesota Power included no long-term incentive compensation in the test year.[306]

222. OES did not object to the proposed AIP expense.

223. The OAG objects to the proposal, arguing that base compensation is sufficient and that ratepayers should not be responsible for incentive compensation of any kind. The OAG also argues that Minnesota Power's AIP bonuses would be skewed in favor of highly compensated employees, since the target bonus for the top ten compensated employees (cumulatively) is $557,000.[307]

224. Even when the change to base compensation is factored into AIP expense, the total amount is approximately $2 million less than the amount of incentive compensation approved in the last rate case.[308] The Company has not increased its proposed incentive compensation; rather, the Company has substantially decreased it. Minnesota Power has demonstrated that its request to recover $1,713,430 in AIP expenses is reasonable, consistent with the Commission's order in the last rate case, and should be included in the 2010 test year budget.

D. Employee and Board Expense.

225. The Company built its test year budget for employee and board expense based on a projected 2010 Test Year, rather than an historical budget. Because the Company does not prepare budgets for employee expenses on an individual employee basis, or for individual expense items, the Company used 2008 actual expenses as a proxy for 2010 expense levels.[309] The Company did not believe that 2009 was the appropriate basis of comparison because the cost reductions taken in 2009 were in response to a severe and unprecedented downturn in the economy, and the Company did not believe these reductions were sustainable in 2010 or into the future.[310]

226. The Company initially budgeted $2.355 million in employee and board expenses for the test year.[311] In an effort to minimize the time and expense often focused on debates regarding claimed employee expenses, the Company removed $514,000, or approximately 21%, of its claimed employee and board expenses, to arrive at a total of $1.841 million in employee and board expenses for the 2010 test year.[312]

227. To accomplish this, the Company excluded 100% of 2010 employee expenses for its top six executives and one executive assistant, and it removed 25% of

[306] Ex. 37 at 17 (Carter Direct).
[307] Ex. 74 at 33-35 (Smith Direct); Ex. 76 at 19-23 (Smith Surrebuttal).
[308] Ex. 39 at 13 (Carter Rebuttal).
[309] Ex. 35 (DeVinck Rebuttal) at 5-6.
[310] Ex. 35 at 6 (DeVinck Rebuttal).
[311] Ex. 36 at Schedule 1, page 2 (DeVinck Surrebuttal).
[312] Ex. 35 at 5 (DeVinck Rebuttal); Ex. 36 at 9 and Schedule 1 (DeVinck Surrebuttal).

employee expenses for six other company officers. The Company also excluded 100% of its dues to two country clubs. These exclusions amount to $334,164.[313]

228. The Company also removed all board costs except those related to board member compensation and for travel other than to one annual board meeting held in Florida. This exclusion amounts to $180,250.[314]

229. The Company chose this methodology because it was simple and straightforward; to achieve the goal of identifying a reasonable exclusion to minimize ratepayer costs; and to minimize the expense of debating over individual, small cost items.[315]

230. The OAG performed a detailed review of the Company's 2008 and 2009 employee expenses. It found, not surprisingly, that employee expenses were higher in 2008 than in 2009. Total credit card expense, which includes employee expenses, O&M expenses, and regulated and non-regulated expenses, fell from $11.2 million in 2008 to $8.6 million in 2009.[316] As noted above, total employee expenses for 2008 were 2.355 million before the Company began excluding expenses for the 2010 test year; if the record contains information about total employee expenses for 2009, the Administrative Law Judge is not able to locate it. It appears that in 2009 the expense levels of some of the executives ranged from one-fifth to one-half the amounts paid in 2008.[317]

231. The OAG offered several approaches to reducing the claimed test year expenses. First, the OAG proposed to exclude 100% of expenses for the top 12 Company executives (in contrast to the top six excluded by Minnesota Power), along with three additional vice presidents and the executive assistant.[318] The OAG's explanation for this recommendation was that it could find no "principled distinction" between the groups of executives for whom there was a 25% exclusion and those for whom there was a 100% exclusion, since their expenses were similar.[319] The total amount of the additional exclusion based on this method would be $190,237 (which would be subtracted from the claimed expense of $1.841 million). The total of all executive expenses removed (including those already removed by Minnesota Power) would be $483,402.[320]

232. The OAG also reviewed the credit card charges and expense reports of these executives and concluded that it would not be appropriate to charge ratepayers for approximately 70% of the expenses incurred for 2008 and 2009; it accordingly

[313] Ex. 6 at Work Paper E-10, page 1.
[314] Ex. 34 at 10 (DeVinck Direct); Ex. 6 at Work Paper E-10, page 2.
[315] *Id.*
[316] Ex. 75 at RLS-8 (Smith Rebuttal).
[317] Ex. 74 at 46-50 (Smith Direct).
[318] *Id*. at 45.
[319] *Id.*
[320] Ex. 75 at 11 (Smith Rebuttal).

recommended, in the alternative, that 70% of the 2010 expenses of these executives could be excluded, in the amount of $131,572.[321]

233. The OAG did not specify the criteria it used to determine that expenses were not properly charged to ratepayers. Examples of expenses deemed excludable ranged from attendance at an executive education program at the Carlson School of Management at the University of Minnesota; attendance at Edison Electric Institute meetings; lunches and dinners with employees and company consultants; meetings with analysts in New York City; attendance at management meetings and conferences; attendance at a utility executive course; trips to Board meetings; meals during working lunches; department holiday parties; lodging and meals to meet with counsel in Minneapolis; meetings with the Minnesota Chamber of Commerce; and lodging and meals during the last rate case.[322]

234. Second, the OAG reviewed the credit card statements and expense reports of a sample of non-executive employees. Based on its review, it concluded that 7% of credit card charges of non-executives should be excluded from rates because 7% of the reviewed charges were deemed inappropriate for recovery from ratepayers. Although the OAG recognized that total credit card charges for 2008 ($11.2 million) included executive expenses and employee recognition expenses (for which it recommended separate adjustments), the OAG proposed reducing the revenue requirement by 5% of the total $11.2 million in credit card charges, or $715,399.[323]

235. The OAG again did not specify the criteria used to determine that credit card expenses were not properly charged to ratepayers, except to say that these expenses "pertain to charges which should properly be borne by the employee and not the ratepayer, such as meals at local establishments, personal items, and the like."[324] Examples of expenses deemed excludable are lodging, transportation, and meals while traveling; team meetings at restaurants; flowers for funerals; cards and gift cards for employees; paper supplies; retirement dinners; snacks; landscaping expenses; appreciation gifts; a vacuum cleaner; tools for Taconite Ridge project; attendance at EEI meetings; training lunches; a coffee maker; temporary fishing licenses; computers ($65,000 worth); holiday parties; and overtime meals.[325]

236. Third, the OAG reviewed Minnesota Power's credit card statements specifically for employee recognition events. In 2008, the OAG maintains that Minnesota Power spent $506,541 on employee recognition events (including cards, flowers, food and beverage, gifts, cakes, and other). This category includes

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[321] Ex. 75 at 14 (Smith Rebuttal). The executive expenses the OAG deemed excludable are itemized in RLS-3.
[322] *See generally* Ex. 75 at RLS-3
[323] Ex. 75 at 18 (Smith Rebuttal).
[324] *Id*. at 15.
[325] *Id*. at RLS-7.

administrative assistant expenditures for similar reasons. The OAG recommends excluding this amount from the test year.[326]

237. Minnesota Power also calculated its employee recognition expenses for both 2008 and 2009, in response to information requests from the OAG. In 2008, the Minnesota jurisdictional expense for employee recognition was $405,793; in 2009, the Minnesota jurisdictional expense was $220,539. These amounts include employee recognition events, retirement and anniversary gifts, safety incentives to reward safe work practices, holiday celebrations and gifts, employee social concerns, and an employee renewal dinner.[327] If the safety incentive expenses were removed, the totals would be $355,022 and $183,749 for the Minnesota jurisdiction in 2008 and 2009, respectively.

238. Finally, the OAG recommends that $10,023 in expenses related to the dedication of the Taconite Ridge Energy Center Wind Farm in June 2008 be disallowed. The OAG concluded that expenses for graphics, landscaping, advertising, photography, and entertainment should not be charged to ratepayers.[328]

239. In total, the OAG's proposed adjustments are about $1.4 million (if all executive expenses are excluded and EEI membership dues are addressed separately, below); or $1.3 million (if 70% of executive expenses are excluded and EEI membership dues are addressed separately).[329] The OAG also recommended that Minnesota Power be required to implement an Employee Expense Compliance Plan similar to that adopted by Xcel Energy in its last rate case.[330]

240. The Administrative Law Judge concludes that neither the Company nor the OAG have adequately addressed the issue whether the test year employee travel and entertainment expenses are reasonably related to the provision of utility service. The Company's approach of categorically excluding certain employee expenses is straightforward and easier to follow than the OAG's method. The removal of all expenses for the top six executives and for board members and country clubs was a step in the right direction, but this approach does not easily lend itself to a critical review of the justification for either the initial total or the subsequent exclusions.

241. There are significant problems, however, with the numbers proposed by the OAG. First, the OAG has included more than the Minnesota jurisdictional amounts of these expenses in its totals.[331] In addition, as Minnesota Power made clear in its responses to information requests, employees are allowed to use company credit cards for O&M expenses. The $11.2 million in credit card expenses referenced by the OAG includes $5.2 million in materials procurement, $1.5 million in charges billed to affiliates and non-regulated activities, and $0.9 million for phone and data services. More

[326] Ex. 75 at 37 (Smith Rebuttal).
[327] *Id*. at RLS-16 (Response to IR 624); RLS-12 Part 2 (Attachment to IR 624a.1).
[328] *Id*. at 32-33.
[329] *Id*. at 37.
[330] Ex. 74 at 53 (Smith Direct).
[331] Ex. 36 at 7 (DeVinck Surrebuttal).

importantly, only $2 million of the $11.2 million total was attributable to employee expenses in 2008.[332] Moreover, there is substantial overlap in the OAG's categories of expenses that should be excluded: some of the executive expenses the OAG proposes to exclude also appear as credit card purchases that should be excluded, and the same is true for virtually all the excluded employee recognition expenses. The OAG's proposed exclusions based on credit card expense, in general, are not reliably calculated.

242. Another problem with the analysis presented by both the Company and the OAG is that they have offered no systematic way of analyzing what is an appropriate expense and what is not. The Company has no written policies to limit the amounts of expenses that should be charged to ratepayers. Although most of the travel, hotel, lodging, and conference expenses criticized by the OAG appear to be legitimate trips for business or conferences that are reasonably related to the provision of utility service, there is no apparent control over the amounts of those expenses. The expenses associated with opening a major new source of wind generation at Taconite Ridge appear to be reasonable; in addition, they were incurred in 2008, prior to the last rate case. Overtime meals and meals while participating in training events are expenses that also have a direct connection to the provision of utility service, and about 30% of employee meal expenses are mandated by a collective bargaining agreement.[333] Meals associated with employee meetings may or may not be appropriate, but it is difficult to draw that line based on this record.

243. The thrust of some of the OAG's arguments, however, clearly has merit. As the Company's experience in 2009 demonstrates, employee expenses are discretionary in a way that pension and other employee benefit expenses are not. And as important as employee recognition expenses may be to the corporate culture of Minnesota Power, it is difficult to see the connection between greeting cards, cake, flowers, retirement and holiday parties, and the provision of utility service. It is somewhat difficult to determine from the record, however, exactly what proportion of the claimed test year expenses would be attributable to such employee recognition events.

244. The Administrative Law Judge concludes that $1.84 million in discretionary employee expense, for a company with approximately 1,250 employees, is a large number. The Administrative Law Judge recommends that the Commission make two further adjustments to Minnesota Power's employee expense budget. First, an additional $190,237 should be removed from the test year, as advocated by the OAG, to account for the absence of written policies on what expenses should reasonably be charged to ratepayers. In addition, $355,022 for employee recognition events should be excluded. This is the amount Minnesota Power calculated for the Minnesota jurisdiction's 2008 employee recognition expenses, after the Administrative Law Judge removed safety incentive expenses. Although the resulting number is not perfect, it is a reasonable proxy for expenses that should not be passed through in

[332] Ex. 36 at 9-10 & Schedule 2 (DeVinck Surrebuttal).
[333] Tr. 2:36.

rates. Without these adjustments, Minnesota Power has not established that its test year expense is reasonable.

245. The problem with accurately categorizing these expenses should not arise again in the future, as utilities are now required under Minn. Stat. § 216B.16, subd. 17, to file schedules separately itemizing travel, entertainment, and related employee expenses with any rate case petition. The statute sets forth specific requirements for the way in which expenses must be itemized and the detailed documentation that must be included.[334]

246. The Administrative Law Judge also recommends that the Commission require the Company to include employee recognition expenses in the required itemized schedule in the next rate case, in addition to the categories specified by statute. In addition, the Administrative Law Judge recommends that before the next rate case, Minnesota Power should be required to develop written policies for the inclusion in rates of employee travel, lodging, and meal expenses and implement an employee expense compliance plan to ensure that the policies are followed.

E. Advertising Expense.

247. The Company originally budgeted $280,828 for test year advertising expenses. The budget includes $25,000 for safety advertising; $100,000 for employment advertising; $15,000 for telephone book listings; and $140,000 in other advertising expense.[335]

248. Minnesota Power's actual advertising expenses in 2008 were $365,576; in 2009, the actual expense was $155,482. The Commission approved $178,107 for advertising expense in the Company's 2008 rate case.[336]

249. After reviewing examples of the Company's advertising in light of the statutory criteria for considering advertising expenses, OES concluded that the Company's examples are eligible for recovery in rate cases; however, OES concluded that the Company failed to show the reasonableness of the amount of expenses it proposes to include in the 2010 test year. OES recommended setting test year expenses at $155,482, the amount spent in 2009. In its view, the Company's conservation advertising budgets were too variable to include in base rates.[337]

250. OES asserts that the appropriate venue for the Company to request recovery of conservation expenses, including advertising, is through the Company's Conservation Improvement Program (CIP), which allows utilities to track costs and adjust rates over time as expenses fluctuate.[338]

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[334] 2010 Minn. Laws ch. 328, § 2.
[335] Ex. 102 at 2 (Davis Direct).
[336] *Id*. 2-5; Ex. 47 at Schedule G-1, page 2.
[337] *Id.* at 3-5.
[338] *Id*. at 4-5.

251. The Company responded that the 2009 expenses were below its budgeted 2009 expenses because of the economic downturn. It agreed to reduce the test year level by $70,000, by eliminating one unidentified program, which it stated was not essential, bringing the amount of test year advertising expenses to $210,828.[339]

252. Minnesota Power attributed the increased advertising cost to growth in conservation-related advertising. One source of the increase was the "Eleven Simple Ways to Conserve" advertising campaign, on which the Company spent $139,171 in 2008 but only $2,494 in 2009.[340] In total, the Company spent $157,460 on conservation advertising in 2008, but only spent $23,982 on similar advertising in 2009.[341]

253. The Company also asserts that the variability of its advertising spending is not connected to the level of spending but rather to the specific campaigns it runs from year to year, and, while it will not continue with the "Eleven Simple Ways" campaign in 2010, it will utilize other general advertising messages promoting conservation in 2010 and succeeding years.[342]

254. The Company argues that it should be able to recover its conservation-related advertising costs as part of this rate case as contemplated by Minn. Stat. §216B.16, subd. 8. (2008).[343] The Company contends that the conservation-related advertising expenses included in its proposed test-year budget are general advertising programs encouraging conservation. The CIP promotional messages, in contrast, are for specific programs targeted to specific audiences (for example, messages to new home-builders, or to people purchasing heating and cooling systems). The Company argues that, to include general conservation advertising expenses with CIP specific programs would have a negative impact on the intent and administration of the CIP program.[344]

255. Minn. Stat. § 216B.16, subd. 8 (b)(1), permits the commission to approve a rate including advertising expenses for information which "is designed to encourage conservation of energy supplies . . . ."

256. Minnesota Power has established that the types of advertising included in its budget are recoverable in rates. The reduced test year amount of $210,828 includes $70,000 for conservation advertising, which is only $10,000 more than the Company spent during 2009. The OES has not criticized the amount of other budgeted advertising expenses. The Company has demonstrated that its request for recovery of test year advertising expenses is reasonable at the reduced amount of $210,828.

[339] Ex. 9 (McMillan Rebuttal) at 31.
[340] Ex. 102 at 4-5 & CTD-3, page 2 (OES IR 604).
[341] *Id.*
[342] Minnesota Power Reply Brief at 38.
[343] *Id*. at 39.
[344] *Id.*

F. Economic Development Expense.

257. The Company seeks recovery of 100% of its budgeted test year economic development expenses of $316,131.[345] Economic development programs are designed to retain and promote growth in the demand for electric energy by commercial and industrial customers.[346] The Company devotes the bulk of its economic development funding to organizations in the community, such as Area Partnership for Economic Expansion (APEX), which are engaged in economic development.[347]

258. In the 2008 rate case, the Commission allowed $367,000 in economic development expense, which was 50% of the Company's economic development expenses. In that case, the Commission noted:

> [T]he Company did not undertake any quantitative or objective analysis with respect to economic development costs. The Commission will not attempt to dictate at this time what showing might be required to satisfy the OES, or the Commission, that such programs merit 100 percent recovery. However, the Commission will require that the Company prepare, in consultation with the OES, an analysis of the ratepayer benefit achieved by the economic development costs it seeks to recover from ratepayers to be filed in the Company's next rate case.[348]

259. In the same analysis, the Commission concluded:

> While the Commission recognizes that Minnesota Power's efforts with respect to these many programs provide a positive impact on the community, the costs of these programs should not be borne entirely by ratepayers, but also by shareholders who also clearly derive benefits. Hence, ratepayers should not pay for such programs in full.[349]

260. Since the last rate case, the Company eliminated one of the two economic development staff positions and made other cost management efforts.[350] It is not clear how much the Company spent on economic development in 2009.

261. OES maintained that the Company's ratepayer impact analysis was still not sufficiently precise and identified additional steps it believes should have been included in the Company's analysis.[351]

262. The Company submitted a revised ratepayer impact analysis in rebuttal. It also argued that year-to-year variations in the programs and the lead times necessary

[345] Ex. 8 at 22 (McMillan Direct).
[346] Ex. 102 at 6 (Davis Direct).
[347] Ex. 9 at 32 (McMillan Rebuttal).
[348] *2008 Rate Case Order* at 56.
[349] *Id.* at 57.
[350] Ex. 8 at 22-23 (McMillan Direct).
[351] Ex. 9 at 32 (McMillan Rebuttal).

to show results make it impossible to precisely determine benefit.[352] The Company identified three projects being considered in Minnesota Power's service territory as a result of its economic development activities. The Company's revised analysis, which applied a 50% reduction to the net margin to reflect free ridership and partial funding of development assistance, shows that the positive impact on the Company over a period of 10-20 years far outweighs the initial investments.[353]

263. In response, OES maintained that, although the ratepayer analysis was significantly improved, it was still insufficient because the analysis failed to adequately provide an analysis of the percentage of funds provided by the Company to the customer and did not estimate the percentages of revenues that would have remained, or located, in the Company's territory even without economic development assistance.[354] OES recommended disallowing all of Minnesota Power's economic development expenses.[355]

264. The OES urged that, for future rates, the Company should be required to provide an estimate of the total resources that would be spent if potential new customers are added and show whether, with an assumption of 25% free ridership and a reasonable allocation of revenues to the Company's economic development program, the program would be cost-effective.[356]

265. The OAG recommended that the Commission continue with the Commission's previous 50% allowance of economic development expenses, asserting that shareholders should contribute to the costs of programs from which they clearly benefit.[357]

266. The Administrative Law Judge agrees that the Company has adequately demonstrated that its economic development programs provide some benefit to ratepayers. In addition, public comments filed by APEX and several other economic development groups support the proposition that the Company cannot provide meaningful economic development leadership using fewer resources than it requests in this case.[358] Because the Company has trimmed these expenses substantially to less than half the amount allowed in the last rate case, the Administrative Law Judge recommends that the Commission allow the full amount of the Company's requested economic development expenses ($316,131). The Company should be required to further develop its ratepayer impact analysis, as recommended by OES and the OAG, if it seeks any larger sums in its next rate case.

[352] Ex. 9 at 33-35 (McMillan Rebuttal).
[353] *Id.* at 33 & Rebuttal Schedules 2 and 3.
[354] Ex. 103 at 7-8 (Davis Surrebuttal).
[355] *Id*. at 6-12.
[356] *Id.*at 11-12.
[357] Ex. 74 at 28-32 (Smith Direct).
[358] *See* Finding No. 19.

G. Charitable Contributions.

267. The Company budgeted $1,295,000 in test year operating expenses for charitable contributions, requesting recovery in rates of 50% of those costs, or $650,000.[359]

268. In its last rate case, which was based on a 2008-2009 test year, the Company was awarded $552,000 in rates for expected charitable contributions of $1,105,100.[360]

269. In fiscal year 2009, the Company budgeted $1,280,050 for charitable contributions, but actual contributions were limited to $654,000 as a cost-cutting measure.[361]

270. The OES and OAG initially proposed allowing Minnesota Power to recover 50% of charitable contributions budgeted for 2009, or $327,000, based on the Company's sharp decrease in charitable contributions in 2009.[362]

271. OES later revised its recommendation, stating it is reasonable to assume that the Company will contribute more during the test year than it did in 2009. OES arrived at its revised recommendation by using the average of actual contributions made in 2007 through 2009: $887,977, with a recommended allowance of 50%, or $443,989.[363]

272. The Company maintained that it is more appropriate to use its test year amount, which represents a natural progression of giving from $929,000 in 2007, $1,068,000 in 2008, the originally-budgeted amount of $1,280,000 in 2009, and the $1,296,000 budgeted for 2010. The Company also states that the Minnesota Power Foundation takes the volatility out of the Company's charitable contributions and provides assurance that the Company will actually give at the budgeted level.[364]

273. The Administrative Law Judge recommends that the Commission accept the OES recommendation to allow $443,989 for charitable giving, calculated by averaging the actual contributions in 2007-2009, a time period that reflects periods of greater and lesser economic stability. The existence of the Minnesota Power Foundation did not ensure that charitable contributions were made as budgeted in 2009.

H. Unamortized 2008 Rate Case Expenses.

274. The Company's initial filing sought recovery of more than $396,000 for its unamortized rate-case expenses associated with the 2008 Rate Case.[365] In rebuttal,

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[359] Ex. 9 at 29 (McMillan Rebuttal).
[360] Ex. 102 at 15 (Davis Direct).
[361] Ex. 102 at 16 (Davis Direct).
[362] *Id*. at 15-16 (Davis Direct); Ex. 74 at 27 (Smith Direct).
[363] Ex. 103 at 2-3 (Davis Surrebuttal).
[364] Ex. 9 at 29-30 (McMillan Rebuttal).
[365] Ex. 47 at 26 (Podratz Direct).

the amount was reduced to $374,381 to correct the allocation to non-regulated operations.[366]

275. The OES and OAG objected to recovery of unamortized 2008 rate case expenses. OES argued that it was not appropriate for Minnesota Power to recover from ratepayers the costs of two rate cases. OES recommended that the Company's unamortized expenses from the 2008 rate case be disallowed entirely.[367]

276. There is no true-up mechanism between rate cases to account for expenses that were either over-recovered or under-recovered in a previous rate case. One reason for this ratemaking policy is that utilities largely control the timing of their rate cases. These decisions are based on the utility's own assessment of its level of investment, sales and expenses. A utility may file a rate case prior to the end of the amortization period of a rate case, but if the utility makes such a choice then it does so knowing that it will forego collection of the unrecovered balance of such expenses. Fairness dictates that there should not be a penalty to the Company's ratepayers for the Company's choice to file its rate case before the end of the Commission-approved amortization period.[368]

277. Allowing the Company to recover rate-case expenses from the 2008 rate case would be inconsistent with recent Commission precedent. Unless there are special circumstances to warrant different treatment, normal ratemaking policy does not allow a utility to recover costs outside its rate case test year period. This limitation is a corollary to the limitation that protects a utility from having to include past out-of-period revenues in a rate case.[369] In this case, the Company has failed to demonstrate special circumstances that would warrant different treatment.

278. The Administrative Law Judge recommends that the Commission deny the Company's request to include the 2008 unamortized rate case expenses in the 2010 test year budget.

I. Current Rate Case Expenses.

279. The Company projects $1,996,894 in rate-case expenses for the current rate case.[370] The Company's total estimate was based on the following four categories of cost: (1) Professional Services, $1,450,000; (2) MPUC Assessments, $512,500; (3) Intervenor Compensation, $18,426; and (4) Other Costs, $95,000.[371]

280. These costs were allocated in part to non-regulated activities, as the Commission directed in the last rate case. The Company proposed to amortize those costs over three years, resulting in an annual expense of $665,631. The Company

[366] Ex. 50 at 22 (Podratz Rebuttal).
[367] Ex. 104 at 15 (Lusti Direct).
[368] Ex. 104 at 13-14 (Lusti Direct).
[369] *Id*. at 14.
[370] Ex. 48 at 24-25 (Podratz Direct).
[371] Ex. 104 at 15 (Lusti Direct).

would agree to limit recovery to the three-year period to avoid over-collection, as it did in its last rate case.[372]

281. OES did not challenge the Company's estimate of the amount of rate case expense, but it opposed the use of a three-year amortization period.[373] OES recommended instead that the Company be required to amortize its rate case expenses over four years. OES based its recommendation on the average time periods between the Company's rate cases between 1976 and 2009, which was at least four years. OES pointed out that the four year average includes time when the Company was expanding its system and did not have access to rider recovery as it does today. The average was also affected by one 14-year gap, between 1994 and 2008, when the Company did not file a rate case.[374]

282. The OAG recommended that the Company be allowed to recover only half of its projected rate case expenses, or $998,447, on the theory that the Company has not controlled its rate case expenses. The OAG also recommended that the Company amortize its rate case expenses over seven years (the average time between rate cases from 1987 to 2008) and include this amount as a normalized rate-setting expense. The OAG also recommended that the Company be required in future to seek competitive bids for rate case legal and consulting services.[375]

283. There is no factual basis for the OAG's claim that the Company has failed to control its rate case costs. These costs are higher than allowed in the last rate case, but the Company has explained the reasons. There is no evidence that costs should have been lower.[376]

284. The Company argued that a new rate case could be triggered by the loss of a single Large Power customer or a decline in Large Power sales coupled with increased costs and capital expenditures. It reiterated that it will be undertaking extensive capital projects in 2011, 2012 and beyond, at a time when the rate of economic recovery is uncertain. These plans, coupled with unavoidable cost increases, indicate the Company will file its next rate case within three years.[377]

285. The Commission used a three-year amortization period for rate case expense in the Company's last two rate cases, and the parties agreed in this case that use of a three-year amortization period was appropriate for Boswell 4 O&M expenses. The Administrative Law Judge recommends that annual expense of $665,631 be recovered for a three-year period, after which no recovery should take place.

[372] Ex. 48 at 24-26 (Podratz Direct).
[373] Ex. 104 at 15 (Lusti Direct).
[374] Ex. 104 at 16 (Lusti Direct).
[375] Ex. 71 at 59-60 (Lindell Direct).
[376] Ex. 48 at 24-25 (Podratz Direct).
[377] Ex. 49 at 25 (Podratz Rebuttal).

J. Lobbying Expense.

286. The Company did not seek to recover a specific category of test year expenses relating to "lobbying activities."

287. In its direct testimony, the OAG argued that non-salaried lobbying costs, salaries of employees who did lobbying work, and costs associated with companies providing professional services in support of Minnesota Power's lobbying initiatives should be excluded. The OAG estimated that this exclusion would amount to at least $200,000, and it requested that Minnesota Power provide test year cost information in rebuttal.[378]

288. In rebuttal, Minnesota Power described its lobbying activities as being concentrated on capital spending for environmental and renewable policy initiatives, as well as conservation and efficiency initiatives. In addition, the Company has lobbied to prevent property tax increases and to maintain or improve personal property tax exemptions. The Company maintains that all of these activities are aimed at keeping costs down to the benefit of ratepayers. Specifically, the Company pointed to recent successful efforts to oppose a personal property tax increase that would have raised the Company's taxes by $6 million and to postpone implementation of mercury reduction standards for Boswell 4, which allowed the Company to delay the installation of certain emission-reduction equipment that would increase costs for ratepayers.[379]

289. In rebuttal, the OAG argued that $350,000 in expenses should be disallowed as lobbying expenses. Included in this amount is $105,335 for non-salaried lobbying costs; a portion of the salaries of three employees whose job responsibilities include lobbying efforts, the Minnesota jurisdictional amount of which is $115,000; and the entire salary of the Vice President of Regulatory and Legislative Affairs (the amount does not appear to be in the record). In addition, it contends that certain employee expenses should be excluded, such as those associated with the Midwest Governor's meeting, an executive's trip to meet with a lobbyist in 2008, and attendance at Congressional Briefings from the Lignite Energy Council.[380]

290. In response, the Company provided evidence that the Vice President of Regulatory and Legislative Affairs is primarily focused on state regulatory compliance, including developing the Company's positions on regulatory issues, processing the Company's regulatory filings, and coordinating communication with key regulatory agencies.[381]

291. The OAG states that the Commission has been reluctant to require ratepayers to pay for lobbying costs in support of political positions contrary to their convictions or best interests, and it has "consistently rejected rate recovery of lobbying

[378] Ex. 74 at 61-62 (Smith Direct).
[379] Ex. 9 at 24-28 (McMillan Rebuttal).
[380] Ex. 75 at 37-39 & RLS-15 (Smith Rebuttal).
[381] Ex. 10 at 6 (McMillan Surrebuttal).

expenses when that issue has been raised and addressed."[382] The cited language, from the Commission's January 2010 Order in the CenterPoint Energy rate case, was in the context of the Commission's finding that "the record [in CenterPoint Energy] does not disclose the issues on which the Company lobbied, the position taken, or that the Company lobbying was intended to, or did, advance the interests of ratepayers." The OAG also proposes that Minnesota Power should be required to treat lobbying expenses in the manner that Xcel Energy does, by budgeting both employee and contract lobbying expense to FERC Account 426.4 and excluding this category from O&M expenses recovered from ratepayers.[383]

292. Although the Company has supported legislation that generally would minimize costs for ratepayers, some ratepayers might well believe that cost reduction is less important than supporting renewable energy initiatives, limiting mercury emissions, or regulating coal combustion by-products as hazardous waste. The OAG has provided persuasive evidence that contract lobbying expense in the amount of $105,335, in addition to $115,000 in salaried employee expense, should be removed from the test year. The Company has substantiated, however, that the salary of its Vice President of Regulatory Affairs and various other meeting expenses are not lobbying expenses that should be excluded. The Administrative Law Judge accordingly recommends that the Commission exclude $215,335 in lobbying expense from the test year and require Minnesota Power to account for future lobbying expenses by assigning them to a FERC account, as does Xcel Energy.

K. Organizational Dues.

293. Minnesota Power requested recovery of $1.109 million in organizational dues for the test year. OES reviewed the costs for compliance with the Commission's June 14, 1982 Statement of Policy on Organizational Dues and recommended approval of the entire amount, on the basis that these dues are for organizations intended to improve the Company's ability to provide reasonable service to its customers.[384]

294. The OAG proposes to exclude $294,786 for the Company's membership dues in the Edison Electric Institute (EEI) on the basis of its conclusion that "[m]any of EEI's activities are to promote legislation and to conduct typical trade organization activities."[385] In addition, the OAG proposed to exclude some of the travel expenses involved in attending meetings or events of the Association of Edison Illuminating Companies (AEIC) because, while acknowledging that AEIC provides "some ratepayer

[382] Ex. 76 at 33 (Smith Surreubttal).
[383] *Id*.
[384] Ex. 102 at 14 (Davis Direct); Ex. 1 at Schedule G-3, page 1 of 6.
[385] Ex. 75 at 34 (Smith Rebuttal).

benefit," it "also benefits shareholders."[386] The OAG proposed to exclude these expenses in its analysis of employee travel and entertainment costs.[387]

295. The Company provided testimony establishing that the EEI's work with regard to policy issues is of benefit to ratepayers. The Company also demonstrated that EEI provides significant educational and information-sharing services. Because EEI provides these kinds of benefits, all Minnesota investor-owned utilities are members of EEI, and EEI membership dues have been permitted by the Commission in prior rate cases, including all of the Company's rate cases dating back to 1977.[388]

296. The Company established that AEIC does not deal with policy issues, but rather addresses technology issues regarding planning, building and operating electrical systems. The Company is active on six committees that deal with Power Generation, Electric Power Apparatus, Power Delivery, Load Research, Meter and Service and Cable Engineering.[389]

297. The Administrative Law Judge recommends that the Commission allow the costs of EEI membership dues and participation to remain in the 2010 test year budget. In addition, the Administrative Law Judge recommends that the Company be allowed to recover expenses associated with attendance at AEIC committee meetings.

L. Aircraft Expense.

298. The Company budgeted $1.528 million in aircraft expenses for 2010, but it excluded approximately 60% of those expenses from consideration in this case. It seeks recovery of $507,274 on a Minnesota jurisdictional basis for the test year.[390] The Company excluded three-fourths of the routine maintenance that occurs typically only once every four years.[391] The Company also reviewed the 2008 flight log and excluded the cost of any flight to Florida for board of directors' meetings, flights that included employees' spouses, and trips made for marketing and business development purposes.[392] These are the expenses to which the OAG objected in the Company's last rate case, and which led the Commission to allow only 50% of the $1.2 million in aircraft expenses in that case.[393]

299. As a result of these deductions, the Company seeks to recover approximately of 40% of aircraft expenses, or 50% of non-maintenance expenses.[394]

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[386] *Id*. at 34-35.
[387] The OAG did not identify a specific sum of AEIC expenses that should be excluded, but indicated that these expenses were included in the category of executive and non-executive travel and entertainment expenses that, in its view, were excludable. Ex. 75 at 34-35 (Smith Rebuttal).
[388] Ex. 10 at 10-11 (McMillan Surrebuttal).
[389] *Id.* at 9-10.
[390] Ex. 34 at 11 (DeVinck Direct); Ex. 74 at 37 & RLS-24 (Smith Direct)..
[391] *Id;* Ex. 6, Work Papers, Operating Income E-2, page 1 (Initial Filing, Vol. IV).
[392] Ex. 34 at 11-12 (DeVinck Direct); Ex. 6, Work Papers, Operating Income E-2, pages 1-3.
[393] *Id.*; *2008 Rate Case Order* at 45-47.
[394] Ex. 6, Work Papers, Operating Income E-2, page 1 of 3.

300. In 2009, the Minnesota jurisdictional amount of ALLETE's corporate aircraft expenses (without any of the exclusions identified above) was $508,188.[395]

301. The OAG recommends that the Commission disallow 100% of the claimed aircraft expenses in this docket, arguing that corporate aircraft ownership is neither reasonable nor necessary to provide electric service in Northern Minnesota" and that Minnesota Power failed to provide a cost-benefit analysis of aircraft ownership. The OAG also argues that if 2009 were used as the benchmark for the test year, approximately $275,000 would have to be removed to reflect the types of inappropriate expenses removed from the 2008 budget.[396] There is no record support for how the OAG calculated this number, but the record reflects that 19 out of 57 total flights in 2009 involved transportation for board members, spouses of employees or board members, or non-employees.[397]

302. The Administrative Law Judge notes that the Commission found in the last rate case that the Company's use of a corporate aircraft is beneficial in comparison to using alternative transportation in many situations. The Commission framed the issue as whether some proportional share of current aircraft costs reflecting its regulated use should be allowed in rate recovery.[398]

303. The OAG's position that 100% of these expenses should be excluded is inconsistent with the Commission's previous decision. Minnesota Power has followed the Commission's direction in the last rate case and has excluded more than half of its 2008 aircraft expense. The amount it seeks for 2010 appears to be less than the sum the Commission allowed in the last rate case, and it is somewhat more than the Company's expenses would have been in 2009, if similar adjustments had been made. The Company has established that the sum it claims is a reasonable proxy for the aircraft's value to the utility in 2010.

M. Legal and Consulting Expense for Defense of EPA Enforcement Action.

304. The test year included approximately $250,000 of legal and consulting expense (outside of rate case expenses), representing the cost of defending an EPA enforcement action commenced in 2008. The enforcement action alleges violations of the federal Clear Air Act at Boswell 1-4 and Laskin Unit 2 between 1981 and 2000. The Company asserts that it was in full compliance with the law and that it is engaged in ongoing discussions with the EPA regarding the Notice and Finding of Violation.[399]

305. In surrebuttal, the OAG recommended that the Commission exclude these expenses, and the MCEA joins this argument in its brief. They argue that ratepayers

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[395] Ex. 74 at 38 (Smith Direct).
[396] Ex. 76 at 23 (Smith Surrebuttal).
[397] Ex. 74 at RLS-26, pages 3-4 (Smith Direct).
[398] *2008 Rate Case Order* at 47.
[399] Ex. 73 at JJL-3, page 2 of 11 (Lindell Surrebuttal); Tr. 2:197 (Podratz).

should not have to pay legal and consulting expenses due to the Company's "unlawful activities or claimed violations of law."[400]

306. In its last rate case, the Company did not include any expense relating to the claimed violations, although some expense was incurred during the test year used in that case.[401]

307. The Administrative Law Judge recommends that the Commission allow the $250,000 for attorney and consultant fees to be included in the 2010 test-year budget. If a fine is paid, that amount likely should be excluded from any future case. It is premature, however, to exclude costs associated with defending a pending claim.[402]

N. Request for Prefiled Information in Next Rate Case.

308. As noted above, the sales forecast for 2010 is an issue that was resolved between Minnesota Power and OES. Because of the difficulty that OES had in duplicating Minnesota Power's sales forecasts for the Residential and Commercial classes, however, OES requests that the Commission require Minnesota Power to provide all data used in its test year sales forecasts at least 30 days prior to any future general rate case filing; implement a practice of independently verifying the reasonableness of all economic and demographic variables obtained from any third party; provide assumptions and sources in sufficient detail to permit duplication prior to their use in Commission proceedings requiring forecasts; continue working with OES on forecasting issues; and continue working with OES on improving the electronic linkage between CCOSS, forecasting, and revenue models.[403]

309. Although Minnesota Power does not object to working with OES on these issues, it argues that it should not be ordered to do so and that the Commission lacks authority to require pre-filing of information prior to its next rate case. It also objects to the expense involved in independently verifying the reasonableness of economic and demographic variables obtained from any third party.

310. The Commission has broad powers and duties with regard to ratemaking,[404] and it routinely includes in its regulatory decisions various filing requirements for a utility's next rate case. The Administrative Law Judge recommends that the Commission require the Company, as a condition of approving the rate request in this case, to file all data used in its test year sales forecasts at least 30 days prior to any future general rate case filing; provide assumptions and sources in sufficient detail to permit duplication prior to their use in Commission proceedings requiring forecasts;

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[400] Ex. 73 at 27-28 (Lindell Surrebuttal).
[401] *Id*. at JJL-3, page 2.
[402] *See In the Matter of CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-05-1380, Findings of Fact, Conclusions of Law, and Order at 6-10 (Nov. 2, 2006) (allowing recovery of legal expense associated with a remediation plan necessitated by an Office of Pipeline Safety investigation).
[403] Ex. 98 at 20 (Ham Direct); Ex. 100 at 8 (Ham Surrebuttal).
[404] *See* Minn. Stat. §§ 216B.03, 216B.16 (2008).

and continue working with OES on forecasting issues and on improving the electronic linkage between CCOSS, forecasting, and revenue models.

311. The Administrative Law Judge does not understand exactly what OES is seeking through the proposal to require “a practice of independently verifying the reasonableness of all economic and demographic variables obtained from any third party” and does not recommend that the Commission grant this portion of the OES request. The requirement that assumptions and sources be provided in sufficient detail to permit duplication of the results would seem to provide adequate disclosure to identify any problem with “economic and demographic variables obtained from a third party.” If some type of independent verification is needed after the disclosure, it could be provided in the course of the rate case.

VII. DISPUTED RATE DESIGN ISSUES.

312. Rate design, in contrast to the determination of the revenue requirement, is largely a quasi-legislative function. It involves establishment of the utility’s rate structure, such as deciding in what proportions the revenue requirement will be recovered from each customer class. This step of rate making largely involves policy decisions to be made by the Commission.[405]

313. The Commission has historically considered a variety of cost and non-cost factors when designing rates. In addition to the results of a class cost of service study (CCOSS), which is required in all rate cases,[406] the Commission considers other factors, including economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and ability to bear, deflect, or otherwise compensate for additional costs.[407]

314. Nearly all of the contested rate design issues in this case involve questions of which customer classes should be assigned revenue responsibility. These disputes include issues related to the CCOSS methodology, the allocation of the revenue requirement to the customer classes, and rate design for the Residential class.

A. Class Cost of Service Study.

315. The purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for each cost incurred by the utility in providing service. The CCOSS can then be used as one important factor in determining how costs should be recovered from customer classes through rate design.

316. Minnesota Power filed an embedded cost study to allocate fixed generation and transmission costs using the peak and average method the Commission

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[405] *See St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).
[406] Minn. R. 7825.4300 C (2009).
[407] *See St. Paul Area Chamber of Commerce*, 312 Minn. at 260, 251 N.W.2d at 357; *2008 Rate Case Order* at 63.

approved in its 2008 rate case. This method allocates a portion of production plant costs to the classes on the basis of their energy load, using a composite energy/demand allocator.[408] The Company allocated energy costs using the E8760 allocator, which links the time when a customer consumes electricity to the cost of providing electricity at that given time.[409]

317. The only change from the method used in the last rate case was that Minnesota Power revised its method for allocating and collecting conservation expenses on a per-unit-of energy basis.[410] The OES agreed that this method for allocating and collecting conservation expenses is reasonable.[411]

318. Based on the initially proposed CCOSS, rates set to recover Minnesota Power's initially-filed deficiency would have to increase as follows: Residential, 35.44%; General Service, 15.22%; Large Light & Power, 14.06%; Large Power, 15.69%; Municipal Pumping, 15.73%; and Lighting, 8.98%. The average total retail increase was approximately 19%.[412]

319. Based on the revised CCOSS, rates set to recover Minnesota Power's rebuttal deficiency would have to increase as follows: Residential, 29.5%; General Service, 9.3%; Large Light & Power, 9.0%; Large Power, 13.9%; Municipal Pumping, 11.0%; and Lighting, 6.4%. The average total retail increase based on the rebuttal deficiency is 15.4%.[413]

1. Peak and Average Method.

320. In the last rate case, the OES recommended that Minnesota Power be required to use the equivalent peaker method to allocated fixed generation and transmission costs in its next rate case, but the Commission declined to accept this recommendation. In this case, the OES agreed that Minnesota Power's use of the peak and average method to allocate fixed costs was reasonable. It advocated, however, that Minnesota Power be required to provide, in the initial filing of its next rate case, a description and an explanation of each classification and allocation method used in the CCOSS and to justify why that method is appropriate and superior to alternative methods considered. The OES contends that the explanation should rely on the Electric Manual and cost causation principles, but should also be based on the Company's experience and on specific system requirements (engineering and operating characteristics).[414] Minnesota Power agreed with this recommendation.[415]

[408] Ex. 40 at 9-15 (Shimmin Direct).
[409] Ex. 42 at 8 (Shimmin Rebuttal).
[410] Ex. 40 at 9 (Shimmin Direct); Ex. 82 at 9 (Ouanes Direct).
[411] Ex. 102 at 12-13 (Davis Direct).
[412] Ex. 40 at 15 (Shimmin Direct).
[413] Ex. 42 at 13 & Schedule 8, pages 56-58 (Shimmin Rebuttal); Ex. 50 at Schedule 9 (Podratz Rebuttal).
[414] Ex. 82 at 14-15 (Ouanes Direct).
[415] Ex. 42 at 2 (Shimmin Rebuttal).

321. The LPI, while not agreeing with the use of the peak and average method in the CCOSS, did not oppose its use in this case.[416]

322. The OAG opposed the use of the peak and average method, arguing that it over-allocates generation and transmission costs to the Residential class and under-allocates those costs to the Large Power class. OAG argued that plant costs should be allocated based solely on energy usage.[417] The OAG made a similar argument in Minnesota Power's last rate case. There, the Commission declined to require the Company to change its allocation method.[418]

323. There are many possible methods for classifying fixed costs into capacity and energy. The choice of an allocator does not, by itself, set rates. The allocator is a tool for measuring cost, as a starting point for setting rates. The Commission has approved of Minnesota Power's peak and average method in the past, and the OAG has not pointed to any reason why this method cannot be used as a starting point in designing fair and reasonable rates. Moreover, there is no compelling logic to a method that allocates fixed plant costs based solely on energy usage. The Administrative Law Judge accordingly recommends approving the use of the peak and average method in the CCOSS. In addition, based on Minnesota Power's agreement, the Commission should require Minnesota Power to examine other allocation methods and justify the superiority of the peak and average method in its next rate case.

2. E8760 Allocator.

324. The E8760 allocator takes into account the cost of energy based on the time of day the energy is used, and it derives its name from the fact that there are 8760 hours in the year.[419]

325. The OES reviewed Minnesota Power's use of the E8760 allocation methodology, including the calculation of the customer-class-specific allocation factors. The OES recommended approval of Minnesota Power's use of the E8760 allocator in the CCOSS.[420]

326. The OAG, as it did in the previous rate case, objects to use of the E8760 allocator. It contends that the allocator improperly uses MISO Locational Marginal Price (LMP) hourly costs, rather than actual Minnesota Power costs; that the LMP does not reflect line losses; and that the allocator is invalidly calculated using data from different years. The OAG also claims that "mixing and matching" of 2008 LMP prices and 2003 hourly load data invalidates the E8760 and that the rules of the Commission (Minn. R. 7825.2600) allow only a single adjustment per kWh, not a weighted adjustment that accounts for differing energy use among the customer classes. In addition, the OAG argued that Minnesota Power breached the agreement made in the previous rate case

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[416] Ex. 66 at 9 (Baron Direct).
[417] Ex. 71 at 31-35 (Lindell Direct).
[418] *2008 Rate Case Order* at 65.
[419] Ex. 42 at 8 (Shimmin Rebuttal); Ex. 82 at 3 (Ouanes Direct).
[420] Ex. 82 at 4-5 (Ouanes Direct).

by using the E8760 allocator in the Fuel and Purchased Energy Rider (FPE) instead of the Fuel Clause Adjustment (FCA).[421]

327. The E8760 allocator is derived by multiplying the hourly energy usage of each class by the system's LMP cost per hour, then summing and taking the ratio of the sum of each class to the total. The allocator thus yields class-specific responsibilities that take into account class use patterns and time-variant system costs. LMP prices are used as a weight and are equally applied to all classes, so the actual magnitude of the LMP price (as compared to Minnesota Power's or any other utility's hourly cost) has no impact on the results.[422] In addition, the LMP prices by class are based on energy usage, including line losses.[423] Finally, there is no evidence or even argument that the 2003 load data is inaccurate; it is somewhat dated, and Minnesota Power has agreed to begin an updated load research study (see below at Finding 334). But the Administrative Law Judge can see no reason why use of 2003 load data, combined with 2008 LMP price data, compel the conclusion that the ratios developed by the allocator are invalid.

328. The Commission has rejected the OAG's arguments and approved of use of the E8760 allocator in previous cases as a reasonably acceptable calculation of the cost of providing service to each customer class.[424] As the Commission pointed out, the allocator allows the CCOSS to reflect class cost responsibilities with some precision, since energy costs vary, sometimes significantly, from hour to hour. Moreover, as with the peak and average allocator for plant costs, the choice of allocators by itself does not set rates; it is merely a tool for measuring cost. The Administrative Law Judge recommends that the Commission again approve Minnesota Power's use of the E8760 allocator for fuel cost in the CCOSS.

3. Calculation of Net Taxable Income.

329. The OES raised concerns about the manner in which the Company calculated net taxable income by class. The CCOSS as filed determines net taxable income by jurisdiction and class based on present rate revenues, as opposed to basing the calculation solely on class cost.[425] The OES believes that the use of present rates to allocate taxable income by class improperly incorporates rate design decisions from the previous rate case into the CCOSS.[426] The OES recommended that in future cases Minnesota Power should calculate the adjusted net taxable income by class assuming that rate design is based only on the CCOSS, and then allocate income taxes in the CCOSS on the basis of this "theoretical" adjusted net taxable income.[427]

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[421] Ex. 71 at 39-49 (Lindell Direct); Ex. 73 at 19-24 (Lindell Surrebuttal).
[422] Ex. 42 at 8-10 (Shimmin Rebuttal).
[423] *Id*. at 10-11.
[424] *Id*. The Commission has also approved of Xcel Energy's use of the E8760 allocator in its last two rate cases, and it has required Otter Tail Power to use the allocator in future cases. *See* Docket No. E-002/GR-05-1428; E-002/GR-08-1065; E-017/GR-07-1178.
[425] Ex. 42 at 4 (Shimmin Rebuttal).
[426] Ex. 83 at 4-5 (Ouanes Surrebuttal).
[427] Ex. 82 at 12 (Ouanes Direct).

330. Minnesota Power contends that because rate base is classified and allocated independently of present rate revenues, and the required income is calculated by multiplying the claimed rate of return by average rate base, the classification and allocation of income follows and fully reflects the CCOSS without regard to rate design issues and present rate revenues.[428]

331. Minnesota Power also pointed to the January 1992 Electric Utility Cost Allocation Manual of the National Association of Regulatory Commissioners (Electric Manual) to support its position that calculation of income tax based on present rate revenues is appropriate.[429] Minnesota Power's reliance on the Electric Manual, however, is misplaced; the cited portion of the Electric Manual does not pertain to the allocation of costs in a CCOSS.[430]

332. The OAG objected to Minnesota Power's inclusion of any taxes in the CCOSS, arguing that these costs can only arbitrarily be assigned to customer classes.[431]

333. The Administrative Law Judge recommends that the Commission require, in any future CCOSS filed in connection with a rate case, that Minnesota Power calculate and assign income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS, as opposed to using present rate revenues.

4. Load Research Data.

334. Minnesota Power used 2003 load research data in developing the distribution demand allocators for the residential and general service classes and in scaling the budgeted energy used by these classes for the E8760 allocator. Minnesota Power indicated that these load characteristics were relatively stable and reasonably current and accurate, but that it intended to begin a new load research study in the 2011/2012 timeframe, assuming economic conditions have stabilized enough to produce reliable research results. Based on the last study conducted, the Company estimated it would take approximately two years to conduct the study and about 16 additional months to finalize the results. The Company anticipated that new study results would be available in 2013/2014.[432]

335. OES did not object to Minnesota Power's use of 2003 load research data for the present rate case; however, OES recommended that Minnesota Power be required to update its 2003 load research data before its next rate case.[433] OES contends that, at a minimum, Minnesota Power should be required to start a load

[428] Ex. 42 at 4-7 (Shimmin Rebuttal).
[429] Tr. 2:81 (Shimmin).
[430] Ex. 84 (Ouanes Prepared Statement); Ex. 86.
[431] Ex. 73 at 16 (Lindell Surrebuttal).
[432] Ex. 40 at 11-14 (Shimmin Direct).
[433] Ex. 82 at 14-15 (Ouanes Direct).

research study by the end of 2011.[434] The Administrative Law Judge recommends that the Commission require the start of such a study by the end of 2011.

B. Class Revenue Apportionment.

336. In its initial testimony, Minnesota Power concluded that increasing Residential rates by the 35% indicated in the CCOSS was too extreme. Instead, it proposed that rates for the Residential class be increased by the average retail percentage, or 19%, with the remaining deficiency that would otherwise have been collected from the Residential class spread evenly among the other retail classes. This resulted in a proposed apportionment as follows: Residential, 19%; General Service, 19%; Large Light & Power, 18%; Large Power, 19%; Municipal Pumping, 20%; Lighting, 13%; and Dual Fuel, 19%. This proposal would require the non-Residential classes to pay approximately 4% more than indicated in the CCOSS.[435]

337. In Rebuttal, Minnesota Power used the same methodology, proposing that Residential rates be increased by the average retail percentage, 15%, with the remainder spread evenly among other retail classes. This proposed apportionment is: Residential, 15.1%; General Service, 12.3%; Large Light & Power, 11.9%; Large Power, 16.8%; Municipal Pumping, 13.9%; Lighting, 9.3%; and Dual Fuel, 15.1%. This proposal would require the non-Residential classes to pay about 3% more than indicated by the CCOSS.[436]

338. The OES recommended modifying the Company's proposed revenue apportionment based on consideration of the impact of apportionment decisions in Minnesota Power's recent rate case. There, Residential and General Service customers experienced revenue increases of approximately 12%, compared with a 3.8% increase for the Large Light & Power and 2.2% increase for the Large Power classes.[437] OES consequently recommended increasing the Residential class by 12%, increasing the General Service class to cost, and spreading the difference among the remaining classes based on their proportion of revenue.[438] This method would result in the following apportionment of the deficiency: Residential, 12.0%; General Service, 15.2%, Large Light & Power, 20.7%; Large Power, 22.0%; Municipal Pumping, 22.6%; and Lighting, 15.7%.[439]

339. In response to Minnesota Power's rebuttal deficiency, OES proposed using the same method, which would result in apportionment of the increase as follows: Residential, 12.0%; General Service, 9.3%; Large Light & Power, 13.1%; Large Power, 18.1%; Municipal Pumping, 15.1%; and lighting, 10.5%.[440] In the event the Commission

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[434] Ex. 83 at 3 (Ouanes Surrebuttal).
[435] Ex. 48 at 52 & Schedule 13 (Podratz Direct).
[436] Ex. 50 at 31 (Podratz Rebuttal).
[437] *2008 Rate Case Order*, Order Setting Interim Rate Refund, Amending Order After Reconsideration and Approving Compliance Filing, Schedule E-1 (Oct. 29, 2009).
[438] Ex. 87 at 8 (S. Peirce Direct).
[439] *Id*.
[440] Ex. 91 at 4 (S. Peirce Surrebuttal).

approves a lower revenue requirement, OES recommends apportioning the deficiency based on the percent of total revenue required for each class, as follows: Residential, 18%; General Service, 9.96%; Large Light & Power, 16.85%; Large Power, 53.69%; Municipal Pumping, 0.91%; and Lighting, 0.58%. This would move the apportionment slightly more toward cost for all customer classes.

340. The LPI recommends that the deficiency be scaled back to the Commission-approved level; then adding $3 million to the residential class responsibility, and allocating $3 million in credits to the other classes, using each class's subsidy at proposed rates as the basis for the allocation.[441] MCC recommends apportioning any deficiency based strictly on the results of the CCOSS.[442] These approaches rely almost entirely on cost considerations and give little if any weight to non-cost factors such as continuity with prior rates; ability to pay; and ability to bear, deflect, or otherwise compensate for additional costs.

341. The OAG recommends no increase to the Residential and General Service Customer Classes.[443]

342. The OES recommendation represents a significant move toward cost while avoiding rate shock to the Residential class. Specifically, the OES recommendation moderates the revenue increases to the Residential and General Service class customers, which are below their respective costs of service, but which also experienced the greatest percentage increases in rates in the 2008 Rate Case.[444] The revenue apportionment proposed by the OES appropriately considers the cumulative effects of the two rate case increases on customers. The Administrative Law Judge recommends that the Commission adopt the OES approach to apportionment of the deficiency.

C. Rate Design for Residential Class.

343. Minnesota Power's current residential rate structure, known as the Lifeline Rate, is composed of a customer charge (currently set at $8.00) and an inverted block rate structure for the energy charge. The first two blocks of the energy use each month are the "Lifeline" portion of the bill. The first block (the first 50 kWh of energy used each month) is recovered through the monthly charge. The next 300 kWh of energy used each month is charged at 4.773 cents per kWh. Usage over 350 kWh per month falls into the third block, which is currently charged at 8.004 cents per kWh.[445] This rate is currently available to all residential customers, regardless of income.

344. In the last rate case, Minnesota Power proposed moving the Lifeline Rate into a Rider that would be available only to qualified low-income customers. The Commission declined to approve the Lifeline Rider at that time, finding it insufficiently

[441] Ex. 66 at 16-18 (Baron Direct).
[442] Ex. 68 at 3 (Blazar Direct).
[443] Ex. 71 at 37 (Lindell Direct).
[444] Tr. 3:101-03 (S. Peirce).
[445] Ex. 47 at Schedule 15 (Podratz Direct).

developed to serve in lieu of the Lifeline rate. The Commission's decision was based on the fact that poverty rates are disproportionately higher in Minnesota Power's service territory; it was unclear how Minnesota Power would set up a system of identifying low income customers on a year-round basis; and the proposed evaluation and reporting requirements were inadequate. The Commission concluded that the abrupt implementation of the Lifeline rate, without the implementation of a fully functioning low income rider, could inflict economic hardship for the region's many low and fixed income residents. The Commission declined to allow the change, but indicated that it would give serious consideration to eliminating the Lifeline rate structure in the Company's next rate case because it is over-inclusive.[446]

345. In this case, Minnesota Power proposes again to eliminate the Lifeline rate and to establish two rate structures. The standard residential rate offering would have a higher monthly customer charge ($9.75); the first 50 kWh of usage would be recovered in the monthly charge; and energy charges in both the second and third usage blocks would be higher. The Lifeline Rider rate offering would provide the main features of the existing Lifeline rate ($8.00 monthly customer charge, first 50 kWh of usage recovered in the monthly charge; and a discounted energy charge in the second usage block), but would be available only to qualified low-income customers.

1. Monthly Customer Charge.

346. The customer charge is designed to recover fixed costs that do not vary with usage, such as constructing and maintaining infrastructure, reading meters, and conducting billing and collection services. As the Commission noted in the Company's last rate case, the customer charge has two functions, one practical and one grounded in ratemaking policy. The practical function is to help stabilize utility revenues and reduce the risk that the utility will over- or under-recover its revenue requirement due to fluctuations in usage and sales. Its ratemaking function is to ensure that each customer bears responsibility for a certain level of fixed costs regardless of usage.[447]

347. In the last rate case, Minnesota Power proposed increasing the residential customer charge from $5.00 to $10.00; the Commission allowed an increase to $8.00. In this case, Minnesota Power proposes to increase the customer charge from $8.00 to $9.75 for standard residential customers. It proposes to retain the $8.00 customer charge for those who qualify for the Lifeline Rider.[448]

348. Minnesota Power maintains this increase is reasonable based on the results of the CCOSS, which indicate that fixed costs amount to $23.25 per customer per month.[449] In addition, Minnesota Power argues that customers of cooperatives in the same region are subject to much higher monthly service charges, ranging from a

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[446] *2008 Rate Case Order* at 74.
[447] *Id*. at 69.
[448] Ex. 48 at 54-55 (Podratz Direct).
[449] *Id*. at 55.

low of $12.00 for Crow Wing Power in Brainerd to a high of $31.50 for North Itasca Electric Cooperative in Bigfork.[450]

349. The OES recommended maintaining the current $8.00 per month customer charge for standard residential customers as well as those who may qualify for the Lifeline Rider. The basis for the recommendation is that residential customers experienced a $3 per month increase in the last rate case, which became effective less than one year ago.[451]

350. The OAG also recommends no change to the $8.00 per month standard customer charge.[452]

351. The ECC opposed any increase to the customer charge, but proposed as an alternative that the first 50 kWh should no longer be recovered in the energy charge. In addition, the ECC recommended that the Commission adopt an expanded inverted block rate structure based on the rate design from CenterPoint Energy's most recent rate case (Docket No. G008/GR-08-1075).[453]

352. In response to these arguments, Minnesota Power continued to support a $9.75 per month customer charge, but indicated that it would agree with ECC's proposal to maintain an $8.00 per month standard residential customer charge if an energy charge were developed for the first 50 kWh.[454]

353. OES does not support the alternative proposal to begin charging an energy charge for the first 50 kWh in this rate case, because it contends the result would be more financially burdensome to residential customers than increasing the customer charge from $8.00 to $9.75 per month.[455] For example, if Minnesota Power were to charge for the first 50 kWh under the proposed initial block rate of $0.06966 per kWh, customers would experience an increase of $3.48 per month in their bills (50 *$0.06966).[456] The OES recommends requiring the Company to propose an energy charge for the first 50 kWh of usage in its next rate case.

354. The OAG also objects to the ECC proposal to charge for the first 50 kWh of electricity.[457]

2. Proposed Lifeline Rider.

355. Customers with income at or below 50% of the State Median Income would be eligible for service under the Lifeline Rider. This is the income level that qualifies customers under the Commission's Cold Weather Rule to enter into a mutually

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[450] Ex. 48 at 55 (Podratz Direct).
[451] Ex. 87 at 12 (S. Peirce Direct).
[452] Ex. 74 at 63-67 (Smith Direct); Ex. 76 at 34-35 (Smith Rebuttal).
[453] Ex. 53 at 14. (Marshall Rebuttal).
[454] Ex. 49 at 32 (Podratz Rebuttal).
[455] Ex. 91 at 5 (Peirce Surrebuttal).
[456] *Id*. at 6.
[457] Ex. 74 at 63-68 (Smith Direct).

acceptable payment plan with their utility that does not exceed 10% of monthly income, and it is the same eligibility standard used under the Federal Low Income Household Energy Assistance Program (LIHEAP). Receipt of LIHEAP benefits, however, is not required to be eligible for the Lifeline Rider.[458]

356. Minnesota Power proposes to rely on energy assistance and social service agencies within its service area to verify income eligibility of customers and to enroll customers in the Lifeline Rider. Once those agencies determine that a customer is income-eligible, Minnesota Power will code the customer's account to bill them under the Lifeline Rider. Although LIHEAP programs do not determine eligibility on a year-round basis (they process applications between October and May, or until federal funding runs short), Minnesota Power maintains that these organizations have given verbal assurances that they will determine income eligibility for the Rider throughout the year, not just during LIHEAP processing periods. Customers would have to verify their income each year in order to continue taking service under the Rider.[459]

357. In terms of outreach efforts, Minnesota Power would include brochures with the Cold Weather Rule mailings issued each September. In addition, the Company would publicize the availability of the Rider in existing programs that it participates in each year, including the Energy Awareness Expo held each fall and its partnerships with community action agencies, a low-income winter heating assistance task force, and a task force in St. Louis County to end homelessness.[460] Minnesota Power proposes to closely monitor and report annually to the Commission the level of participation in the Rider and to investigate reasons why customers do not participate.[461]

358. During the last heating season, 11,858 of Minnesota Power's customers were enrolled in LIHEAP.[462] In an attempt to identify additional low-income customers, the Company did a mailing to approximately 30,000 potentially income-eligible persons in October 2009. As of January 2010, only 786 customers were newly flagged as LIHEAP-qualified.[463]

359. Minnesota Power estimates that between 30,000 and 36,000 of Minnesota Power's 108,700 residential customers may be eligible for the Lifeline Rider; it has projected, however, that about 20,000 customers would receive discounted rates in the 2010 test year.[464]

360. The OES and the Chamber recommend adoption of Minnesota Power's Lifeline Rider, because it more narrowly targets the intra-class cross subsidization to low-income customers. Because the OES recommends maintaining the customer

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[458] Ex. 45 at 3 (Thompson Direct).
[459] *Id*. at 4-8.
[460] *Id*. at 8-9.
[461] *Id*. at 9-10.
[462] Ex. 52 at 5 (Marshall Direct). This number is similar to the number of customers designated as low-income in Minnesota Power's customer database. *See* Ex. 74 at 73 (Smith Direct).
[463] Ex. 52 at 19 & Schedule 17 (Marshall Direct).
[464] Ex. 47 at 54 & Schedule 1 (Podratz Direct); Ex. 52 at Schedule 14, Schedule 21 (Marshall Direct).

charge at $8.00 per month for all residential customers, however, the OES would modify the discounted second tier for Lifeline customers to be set at the lower of either the current rate or the energy rate approved for the standard residential customers less $0.01266 per kWh, as proposed by Minnesota Power. The OES proposal is intended to differentiate the Lifeline and Standard tariffs.[465] The OES also recommends that Minnesota Power be required to submit annual compliance reports detailing its outreach efforts and the level of customer participation.

361. ECC and the OAG object to replacement of the Lifeline rate structure with the Lifeline Rider. They contend that given the low participation in LIHEAP in Minnesota Power's service area, it is patently unrealistic to assume that 20,000 customers will go through the process of qualifying their income with those same agencies in time to receive discounted Rider rates during the 2010 test year.

362. ECC also argues that the economic circumstances of Minnesota Power's customers have not changed since the last rate case. Unemployment has increased since the filing of the last rate case, with recent highs in January through June 2009 ranging from 9% to 13.5% in counties with the largest concentrations of customers. Moreover, median income levels in the service territory are well below the state-wide median income of $57,318.[466]

363. In addition, the ECC argues that preservation of the Lifeline rate structure will benefit more low-income households than it will harm—more than 60% of low-income customers use less than 750 kWh of energy per month, which is currently recovered in the first two (subsidized) tiers of usage. ECC maintains that if the Rider is adopted, the vast majority of low-income users will end up receiving service under standard rates and will face large increases (on a percentage basis, 19% to 28%) at the second tier of usage.[467] ECC also maintains that the proposed Lifeline Rider does not adequately differentiate between standard residential customers and low-income customers; at the average level of usage and above, there is only about a $4 per month difference in the proposed rates.[468]

3. Inverted Block Structure.

364. As noted above, Minnesota Power proposes to retain its three-tier inverted block rate structure for both the Standard Residential rate and the Lifeline Rider rate.

365. For standard residential customers, Minnesota Power initially proposed to increase the energy charge for the second tier of usage to $0.0.06966 per kWh. For the third tier (usage over 350 kWh per month), it proposed to charge $0.0965 per kWh.[469] These figures were based on the deficiency amount initially calculated by Minnesota

[465] Ex. 87 at 17 (S. Peirce Direct). This proposal would likely result in no increase for the second tier of energy usage. *See* Ex. 49 at 34 (Podratz Rebuttal).
[466] Ex. 52 at 12 (Marshall Direct).
[467] Ex. 52 at 7-8 (Marshall Direct); Ex. 53 at 16 (Marshall Rebuttal).
[468] Ex. 53 at 16 (Marshall Rebuttal).
[469] Ex. 48 at 56 (Podratz Direct).

Power. In rebuttal testimony, the Company proposed increasing the energy rates by the average retail percent increase, or approximately 15%.[470] The proposed energy rates would be reduced accordingly, and would be further reduced if the Commission finds the deficiency to be lower.

366. For those who qualify for the Lifeline Rider, Minnesota Power proposes to maintain the current $8.00 per month customer charge, and to discount the next 300 kWh of energy usage by setting it at $0.05700 per kWh. Usage levels over 350 kWh per month would be charged the same rate for both Standard and Lifeline Residential customers ($0.0965 per kWh).[471]

367. Although the OES has supported the proposal to retain the inverted block rate structure for both standard residential customers and those who qualify for the Lifeline Rider, it has recommended that Minnesota Power be required to begin phasing out its block rate design for residential customers in the next rate case.[472] OES asserts that not charging customers for the first 50 kWh of use each month means that the cost of that energy must be collected in the rates charged in the other blocks. As a result, customers who use larger amounts of energy subsidize customers who use less energy.

368. Specifically, OES is concerned that under this structure low-income households using large amounts of energy end up subsidizing households that use less energy but are not necessarily low-income. According to OES data, of 10,115 LIHEAP-qualified customers, approximately 6,434 (about 60 percent) use less than 750 kWh per month, and about 3,681 (about 40 percent) use 750 kWh per month or more. This latter group of 3,681 low-income customers subsidizes a portion of the energy costs of the 60,462 households that use similar amounts of energy but have not been qualified for LIHEAP assistance.[473] OES maintains that these households would be most hurt by adding usage blocks to the inverted block rate.[474]

369. The OAG recommends retaining the current inverted block rate structure and setting the energy charge for usage between 50 and 350 kWh at 60 percent of the energy charge for usage above 350 kWh.[475]

370. To hold down the monthly charge and to relieve the pricing pressure on the second and third tiers of usage, ECC recommends expanding the inverted block rate structure based on the rate design from CenterPoint Energy's most recent rate case.[476] This proposal would create five monthly usage blocks with increasing rates at each level: Block 1, lowest average summer residential usage; Block 2, up to 80% of residential average usage; Block 3, 80-120% of residential average usage; Block 4,

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[470] Ex. 49 at 30 (Podratz Rebuttal).
[471] Ex. 45 at 3.
[472] Ex. 87 at 12 (S. Peirce Direct).
[473] *Id*. at 16.
[474] Ex. 89 at 3 (S. Peirce Rebuttal).
[475] Ex. 74 at 75 (Smith Direct).
[476] Ex. 53 at 14 (Marshall Rebuttal).

120-150% of residential average usage; and Block 5, more than 150% of residential average usage. ECC proposes that the prices for each block be proportionally the same as those implemented in the CenterPoint Energy case.[477] ECC also recommends that Minnesota Power be required to develop an affordability program specifically targeted to high-usage, low-income customers.

371. OES objects to the ECC's proposed expansion of the inverted block structure, pointing out that the structure approved in CenterPoint Energy's case was part of a pilot project that includes a rate decoupling program. That project has only been in effect a short time, and the Commission has not yet evaluated its effectiveness.[478] In addition, OES maintains that no significant rate design changes should be made in this case, because residential customers are already being asked to cope with a second rate increase in one year, and adding design changes would place an additional burden on some customers and increase the potential for customer confusion.[479] Finally, OES objects to adding usage blocks for the same reason it suggests phasing out the existing blocks: the 3,681 low-income, high-usage households identified above use on average 1,250 kWh per month, and their usage would be charged at the highest rates.[480]

372. Minnesota Power does not agree with the proposal to expand the inverted block structure, contending that its proposal to flatten the energy rates is the best approach to moving rates closer to cost and to simply its residential rate structure.[481]

4. Recommendations.

373. There are no easy answers to these issues, but two conclusions appear to be unavoidable. First, given the economic circumstances of Minnesota Power's residential customers and the size of the rate increase they faced less than one year ago, this is not the time to increase the amount of the monthly customer charge. The only real change in circumstance from the last rate case is that unemployment in Minnesota Power's service area is more pervasive, and there is no question but that many residential customers are experiencing even greater financial distress. In both written comments and at the public hearings, residential customers expressed substantial concerns about the difficulty of adjusting to another rate increase so soon after the last one. Consequently, the ALJ recommends that no change in the monthly customer charge should take place at this time.

374. Second, it is apparent that nowhere near 20,000 low-income customers will go through the process of applying for the Lifeline Rider in time to qualify for it during the 2010 test year, as assumed by Minnesota Power. As a consequence, it does not appear that the Rider will be fully functional during the test year. If the Rider were implemented, it would likely result in 10,000 to 20,000 low-income households receiving

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[477] Ex. 53 at 14-15 (Marshall Rebuttal).
[478] Ex. 87 at 14 (S. Peirce Public Direct).
[479] Ex. 89 at 2 (S. Peirce Rebuttal).
[480] *Id*. at 3.
[481] Ex. 49 at 33 (Podratz Rebuttal).

service at standard rates. The Administrative Law Judge accordingly recommends that the Commission reject the proposed Lifeline Rider.

375. Finally, if the monthly charge is not increased and the Lifeline Rider is rejected as an option, it does not appear to be feasible to retain the Lifeline Rate as it is presently structured. The recovery of the first 50 kWh in the monthly charge would make relatively large increases necessary for energy charges in the second and third blocks of usage, which would result in extreme billing impacts for all low-income customers, regardless of usage level.[482]

376. One way to relieve that pressure is to expand the inverted block structure, as proposed by ECC. Under its proposal, the first two blocks would be discounted, the third block would represent the average residential use, and the last two blocks would represent above-average use. This would ameliorate the amount of the increase projected by the OES for low-usage customers, and it would spread the higher energy charges across more usage blocks for average- and high-usage customers. Although it is not specifically targeted to income, this approach appears to be more reasonably calculated to reach low-income customers than the Rider, based on the record developed in this case.

377. The expansion of the inverted block structure in the manner proposed by ECC would be consistent with the principle that customers should be charged for all usage and with the principle that high-usage customers should receive price signals that encourage them to conserve energy.[483] Although the OES has raised sound objections to expanding the inverted block structure based on the impact on low-income, high-usage customers, those impacts could be mitigated by requiring Minnesota Power to implement an affordability program that specifically targets those customers for help in applying for assistance, conserving energy, and negotiating payment plans when necessary.

378. Less persuasive is the criticism by OES that it is premature to adopt an expanded inverted block structure similar to that adopted in the CenterPoint Energy Case, because the CenterPoint structure is part of a pilot project. In the CenterPoint case, the Commission approved a negotiated agreement that linked a new inverted block structure with a new rate decoupling program.[484] This case is different. Minnesota Power already has an inverted block structure for residential customers; the proposed change would provide two more blocks in order to preserve the benefit of the Lifeline Rate for low-usage customers, and to provide better price signals to high-usage customers. In addition, the Administrative Law Judge concludes that customers would likely be less confused by an expansion of the inverted block structure than by the

[482] Ex. 48 at 56 (Podratz Direct).
[483] *See also* 2010 Minn. Laws ch. 361, art. 5 (amending Minn. Stat. § 216B.16, subd. 15, to provide that affordability programs may include inverted block rates in which lower energy prices are made available to lower usage customers).
[484] *In the Matter of an Application by CenterPoint Energy for Authority to Increase natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order at 13-14 (Jan. 11, 2010).

proposed process for obtaining a discounted rate through the Rider. The Commission could also address customer confusion issues by requiring the provision of consumer education material.

379. The Administrative Law Judge accordingly recommends expanding the inverted block rate structure, as proposed by the ECC, and requiring Minnesota Power to develop an affordability program specifically targeted to high-usage, low-income customers. The program should require Minnesota Power to make proactive efforts to reach these specific customers in order to encourage them to apply for energy assistance.

D. Seasonal Residential, Dual Fuel Residential, and Residential Controlled Access Service.

380. Minnesota Power offers Seasonal and Dual Fuel Residential Service. In the last rate case, the Seasonal Residential customer charge increased from $5.50 to $8.80 per month, and the Dual Fuel Residential charge increased from $5.00 to $8.00 per month. Minnesota Power now proposes to increase the Seasonal Residential monthly charge to $11.00, and the Dual Fuel Residential monthly charge to $9.75.[485] It also proposes to increase the monthly service charge for Residential Controlled Access service to $9.75.[486]

381. OES objects to the proposed increases (at least for seasonal residential and dual fuel residential service), for the same reasons it objected to increased monthly charges for Standard Residential service.[487]

382. Given the recent substantial increases in the monthly charges for these customers, the Administrative Law Judge recommends that the Commission deny the proposal to increase these monthly charges.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Chapter 216B and Minn. Stat. § 14.50.

2. Every rate made, demanded, or received by any public utility shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the

[485] Ex. 47 at 57, 59 (Podratz Direct).
[486] *Id*. at 59.
[487] Ex. 87 at 19, 24 (S. Peirce Direct).

goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer.[488]

3. The burden of proof to show that a rate change is just and reasonable shall be upon the public utility seeking the change.[489]

4. If an applicant and all intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the Commission. The Commission shall accept or reject the settlement in its entirety. The Commission may accept the settlement on finding that to do so is in the public interest and is supported by substantial evidence.[490]

5. In the event the Commission rejects the agreements of the parties, this matter may be extended by 60 days for conclusion of the contested case proceedings under the terms of Minn. Stat. § 216B.16, subds. 1a and 2.

6. The record supports the resolution of the settled, resolved, and uncontested matters identified above. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Rates set in accordance with the terms of this Report would be just and reasonable.

Based upon these Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that the Commission issue an Order providing that:

1. Minnesota Power is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. Within ten days of the service date of this Report, Minnesota Power shall file with the Commission for its review and approval, and serve on all parties in this proceedings, revised schedules of rates and charges reflecting the revenue requirements for 2010 and the rate design decisions based on the recommendations contained herein.

3. Minnesota Power shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

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[488] Minn. Stat. § 216B.03.
[489] Minn. Stat. § 216B.16, subd. 4.
[490] Minn. Stat. § 216B.16, subd. 1a(b).

Dated: August 17, 2010

/s/ Kathleen D. Sheehy
KATHLEEN D. SHEEHY
Administrative Law Judge

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NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, any party adversely affected by this Report may file exceptions to it within 15 days of the mailing date hereof. Exceptions should be filed with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 Seventh Place East, St. Paul, MN 55101. Exceptions must be specific and stated and numbered separately and should include Proposed Findings of Fact, Conclusions and an Order. Exceptions should be e-filed with the Commission and served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply. An original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions or after oral argument, if held. Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 216B.16, subd. 1a, if the Commission rejects or modifies the settlement agreements reached herein, this matter may be extended by 60 days for conclusion of the proceeding.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.